Analysis of the Economic and Environmental Benefits of Market Penetration of Distributed Generation

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Project Scope and Objectives

The primary objective of this study is to evaluate the potential air emissions implications in the U.S. due to economic market penetration of distributed generation. This is done by estimating the economically viable market penetration of various distributed generation alternatives in both the electric utility and industrial customer sectors, and estimating the net changes in air emissions that would result. Those estimated net changes will be a direct function of the cost-effectiveness of each individual technology considered.

For example, if fuel cells were found to be economically viable for a large part of the electric energy market in the U.S., then overall greenhouse emissions would probably decrease if the estimated economic market potential of fuel cells were to be achieved. That is because fuel cells emit significantly fewer air pollutants per unit of electricity produced than the conventional central power plants that they would displace. Conversely, if inexpensive diesel engines were used for a large part of the market, then overall air pollution from generation may actually *increase* due to the higher levels of certain emissions from diesel engines.

Key Study Assumptions

- Market potential for distributed generation in electric utilities is evaluated for new load (load growth) applications only.
- Electric utilities are allowed to own and operate distributed generation, they have confidence in the performance and reliability of distributed generation, and they know where and how to deploy it to obtain system benefits.
- Emissions from distributed generation are netted against the nationwide average emissions from existing utility generation.
- Distributed generation technology availability, cost and performance specifications are based on manufacturers' data, where possible, and from research organizations involved in developing evolving technologies, such as fuel cells.
- Natural gas cost and availability are based on current data and projections.
- Market-based values are used for generation capacity and energy, i.e., the values the utility would pay to the generation market.
- Customers' sources for capital are higher cost than utilities' sources, and customers must pay utility rates for their purchased power. Exit fees and standby charges are not considered, and interconnection fees are assumed to be small compared to the capital cost of distributed generation projects. Only large customer loads, primarily industrial, were considered "at risk."
- Sharing of the benefits of distributed generation between customers and utilities was not considered.

Analytical Approach

Estimating the potential amount of air emissions from utility-owned distributed generation requires a two-step process:

1) Estimate the economic market potential for distributed generation options considered. This estimate indicates the number and/or nameplate capacity of distributed generators that might be installed, given purely financial criteria, and requires the following tasks:

   Electric utility perspective – avoided cost: comparing the cost to the utility to own and operate a distributed generator to the avoided cost for the conventional grid-only option. Avoided costs are calculated using market-based generation costs and avoided transmission and distribution costs. Distributed generation is assumed to address load growth only. Both peaking and baseload applications are studied.

   Customer perspective – bill analysis: comparing the cost to the customer to own and operate a distributed generator to the price for electricity that the customer would otherwise purchase from the utility.

2) Compare total air emissions for the central-only generation scenario to the total air emissions that would result if distributed generation achieves the market shares estimated in Step 1. The difference in total air emissions, positive or negative, represents the net emissions impacts expected from distributed generation.

For this analysis, electric utility customers are restricted to larger industrial/institutional users, for a variety of reasons. In general, they have the wherewithal to assess distributed generation projects, internalize benefits associated with distributed generators and to plan, finance, and seek approval for distributed generation projects.

Utility evaluations are performed for the years 2002 and 2010. Parameters that may change results between those years include: distributed generator efficiency is likely to improve, prices for less mature distributed generators are likely to drop, and the amount of load that distributed generators could serve continues to grow.

Results Overview

Utility Distributed Generation Economic Market Potential

Peak Load Applications

Peaking distributed generation technologies appear to be cost-effective for substantial portions of new load in both years studied (see Table E-1). For example, in 2002, the microturbine is cost-effective for 31.5% of the market, about 6,874 MW. The diesel engine has a market share of about 73.8% (16,105 MW). The other four distributed generator options lie between these two; notable among these is the Advanced Turbine System (ATS) at 68.8% market share. In 2010, improvements in cost translate into increased market shares for all technologies, especially the microturbine and combustion turbine.

If these technologies were to achieve their market potential in 2002, the three turbine-based technologies would result in reduced levels of NO_X, SO_X, and CO_2, and virtually no change in particulates (PM) and volatile organic compounds (VOC); CO increases for the microturbine and combustion turbine, but decreases for the ATS. The three engine-based technologies would result in generally increased levels of NO_X, CO, PM and VOC and reduced levels of SO_X; CO_2 increases for diesels and decreases for dual fuel and spark engines (please see Tables 9 and 10 in Section 5 for details).

Table E-1. Peak Utility Distributed Generation Market Potential Summary

Peaking Distributed Generator Option	2002 Market = 21,822 MW/yr		2010 Market = 22,163 MW/yr	
	%	MW/yr	%	MW/yr
Microturbine	31.5	6,874	67.1	14,871
Adv. Turbine System (ATS)	68.8	15,014	77.7	17,221
Conv. Combustion Turbine	32.5	7,092	72.4	16,046
Dual Fuel Engine	35.1	7,660	49.1	10,882
Otto/Spark Engine	51.5	11,238	53.4	11,835
Diesel Engine	73.8	16,105	74.5	16,511

Baseload Applications

Distributed generation technologies will have a hard time competing with baseload central generation in 2002: market potential is virtually nil, with only the efficient ATS capturing a meager 3% or so of the market applications (see Table E-2). The impact on emissions levels is correspondingly small, as well. The situation is not materially different in 2010, with one notable exception: the advanced fuel cell. Due to projected advances in cost and efficiency by 2010, the advanced fuel cell could capture about 53% of the baseload market, with substantial reductions in all air emissions categories (please see Tables 11 and 12 in Section 5 for details).

Table E-2. Baseload Utility Distributed Generation Market Potential Summary

Baseload Distributed Generator Option	2002 Market = 21,822 MW/yr		2010 Market = 22,163 MW/yr	
	%	MW/yr	%	MW/yr
Microturbine	0.0	0.0	0.0	0.0
Adv. Turbine System (ATS)	2.7	589	2.3	510
Conv. Combustion Turbine	0.1	22.0	0.0	0.0
Dual Fuel Engine	0.1	22.0	0.0	0.0
Conventional Fuel Cell	0.0	0.0	0.0	0.0
Advanced Fuel Cell	0.0	0.0	51.1	11,325

Customer Distributed Generation Economic Market Potential

In three states, Indiana, Louisiana, and Ohio, no distributed generation technologies were cost-effective for customer applications. The results for the other seven states (California, Illinois, Michigan, New York, Pennsylvania, Tennessee and Texas) are as follows:

Microturbines

Microturbines are cost-effective in Michigan and New York for about 10.6 GW of customer load (see Table 24 in Section 6). That level of adoption, extrapolated nationally to 20.7 GW, would decrease most air emissions modestly; the exception being a substantial increase in CO.

Advanced Turbine System (ATS)

The ATS is competitive in all seven states, for a total of 61.2 GW, extrapolated to 119.8 GW nationally (see Table 25). Air emissions would be substantially reduced in all categories except VOC, which would increase by a minuscule 0.4%.

Adding CHP capability to the ATS results in slightly lower levels of market potential: 44.0 GW in six states (excluding Texas), 86.3 GW nationally (Table 26). However, due to the avoided boiler emissions, air emissions are substantially reduced across the board.

Dual Fuel Engines

Dual fuel engines are competitive only in New York and Michigan for 10.6 GW of customer load, 20.7 GW nationally (Table 27). Modest reductions of SO_X and CO_2 are offset by increases in other emissions, most notably CO and VOC.

Conventional Fuel Cell

Primarily due to its high capital and maintenance costs, the conventional fuel cell is not competitive in any of the ten states studied (Table 28).

Advanced Fuel Cell

The advanced fuel cell is cost-effective only in Michigan, for 6.3 GW of customer load (12.2 GW on a national basis) (Table 29). The result would be a 2% reduction in CO_2 emissions and 7% reductions in the other five emissions.

Table E-3 summarizes the market potential for distributed generation in the industrial customer sector, extrapolated to national levels. Also shown is the net change in NO_X emissions that would result from these levels of market penetration, compared to central generation. For complete details of the customer analysis, including estimated emission impacts from other pollutants, please see Section 6.

Table E-3. Market Potential and NO_X Emissions for Customer Distributed Generation

Technology	US Industrial Economic Market Potential (GW)	NO_X Emissions	
		tons (K)	△ (%)
Central Generation	170.9	2,071	0.0
Microturbine	20.7	1,964	-5.2
ATS	119.8	1,219	-41.1
ATS -Cogen	86.3	1,119	-46.0
Dual Fuel Engine	20.7	2,374	+14.6
Conv. Fuel Cell	0.0	2,071	0.0
Advanced Fuel Cell	12.2	1,926	-7.0

Key Conclusions

Utility Peaking Distributed Generators

Economic market potential (MW) for utility-owned peaking distributed generators is substantial: they can provide peaking capacity at lower overall cost than the traditional central generation and wires solution in many cases. But, as noted above, cost-effective peaking distributed generators would contribute a very small part of the energy needed to serve new load, because peaking distributed generators have to run for only a few hours per year to provide the capacity needed to "clip" localized electric peak loads.

Combustion turbine-based technologies offer substantial promise to reduce some key air emissions, relative to utility central generation, if market potential estimates are borne out; other air emissions may increase.

Engine-based technologies would have substantial negative impacts on national air emissions if implemented to the degree their market potential numbers would indicate

Utility Baseload Distributed Generators

Overall, baseload distributed generators have a difficult time competing with the wholesale market (the grid) for electricity that provides lower cost electric energy than most baseload distributed generators can generate. The economic market potential for distributed generators for utility base load applications is likely to be low for the next few years, but should increase slowly over time as the cost and performance of distributed generation technologies improves.

Customer Distributed Generators

Customers will tend to use distributed generators primarily to avoid both peak demand charges and high electric energy prices during on-peak price periods, i.e., to reduce their overall energy bill. Only if a distributed generator is very fuel-efficient, or the local utility rates are high, or if CHP is employed, will customer–owned distributed generators be economic for serving all the customer's electricity needs (baseload operation). In many cases, off-peak energy from the utility is low cost and hard for distributed generation to compete with.

Natural gas and diesel engines are the most attractive option for customer peak shaving, due to competitive equipment cost and fuel efficiency. Combustion turbine based options are somewhat less attractive for peak shaving, but more suitable for baseload operation, particularly if a CHP application exists.

The number of hours during which a utility experiences peak demand (either locally or system-wide) is usually less than 200 hours. But the number of hours that demand charges and high on-peak energy prices apply to customers is more typically about 600 hours per year; in some cases, the economics of utility rates may result in several thousand hours per year in which a customer may cost-effectively employ distributed generation.

Employing CHP allows customers to avoid both electricity costs and the use of gas or other fuel to create heat for industrial processes, improving the overall economics for baseload operation. Furthermore, when crediting distributed generation for "avoided" boiler emissions, the net emissions from CHP distributed generators (generator emissions less avoided boiler emissions) will be lower in many cases than the gross emissions from generation-only plants.

Next Steps and R&D Needs

Since the original intent of this effort was to examine distributed generation emissions "from 30,000 feet", and because the distributed generation technologies and market factors are evolving rapidly, many aspects of this analysis seem worthy of further study or refinement.

Perhaps the most important next step might be to broaden the customer segments to include commercial or even residential sectors, since the price paid for electricity directly determines the customer market penetration. Also, distributed generation technologies continue to advance and expand their market applications. More real-world market factors may now be ready for inclusion or refinement, such as exit fees, standby charges or interconnection costs for customer owned distributed generation; similarly the real availability of natural gas to candidate sites, costs for gas connection, and firmness of service may warrant further analysis. Another emerging market niche is the activation of standby generators especially for temporary service to help utilities get through summer peaks. All of these issues might merit further in-depth examination.

1. Introduction

Project Scope and Objectives

The primary objective of this study is to evaluate the potential air emissions implications in the United States due to the market penetration of distributed generation. This is done by first estimating the economically viable market penetration of various distributed generation alternatives in both the electric utility and industrial customer sectors, and then estimating the net changes in air emissions that would result. A distributed generator's total costs, consisting of capital and variable (energy production) costs, compared to the utility's cost to supply capacity and energy, is the major factor in determining the economic market potential for that type of device. The difference between the total air emissions due to distributed generation plus utility generation, and the emissions that central utility generation alone would have produced, represents the net impacts, positive or negative, attributable to distributed generation.

For example, if fuel cells were found to be economically viable for a large part of the electric energy market in the U.S., then overall greenhouse emissions would probably decrease if the estimated economic market potential of fuel cells were to be achieved. This is because fuel cells emit significantly fewer air pollutants per unit of electricity produced than the conventional central power plants whose energy they would displace. Conversely, if inexpensive diesel engines were used for a large part of the market, then emissions of certain pollutants may actually *increase* due to the higher levels of those emissions from diesel engines relative to central generation.

The Distributed Utility Concept

The Distributed Utility (DU) concept involves the use of modular distributed electric energy generation or storage or geographically targeted demand side management; these technologies are collectively referred to as "distributed resources" (DRs). Distributed resources provide the capacity to supply electric energy when and where needed, within an electric utility's distribution system or at energy end-users' facilities. A comprehensive treatise of the Distributed Utility concept can be found in the Distributed Utility Valuation (DUV) Project Monograph, published by EPRI and NREL [1].

Electric utility interest in distributed resources is growing. Distributed resources may serve as a less expensive option when compared to the traditional utility alternatives, which usually comprise upgrades or additions to central station generation and to transmission and distribution infrastructure (the "wires" solution). For example, electric utilities can use distributed resources to delay, reduce or eliminate the need for additional generation, transmission and distribution equipment. In any given circumstance those costs may include some or all of the following:

- central electricity generation variable costs: fuel, operations and maintenance costs
- central electricity generation new/upgrade plant/equipment cost
- electricity transmission new/upgrade plant/equipment cost
- electricity distribution new/upgrade plant/equipment cost

A utility could also use distributed resources to provide "value-added" services such as high reliability or premium power programs to specific areas within its service area or to specific customers.

New players in the deregulated electric utility industry, such as electric service providers (ESPs), may employ distributed resources as competitive offerings to customers.

Electric utility customers may install distributed resources to reduce overall energy costs ("bill management"), or to provide elements of electric service not available from the utility, such as high electric service reliability, high quality power or heat for industrial processes.

Given these premises and emerging trends in the electricity marketplace, there are strong indications that utilities, their customers and their competitors (e.g., ESPs) may use distributed generation to reduce costs and/or to expand services. If so, there are potential implications for total air emissions. The goal of this study is to give the U. S. Environmental Protection Agency a better understanding of the potential for economic deployment of distributed generation and what the resulting changes in total air emissions might be on a nationwide basis.

Analytical Approach

Estimating the potential air emissions impacts from distributed generation requires a two-step analytical process. First, the economic market potential for distributed generation is estimated, given the available technologies and their costs, for electric utilities on a national basis in 2002 and 2010, using the DUVal economic model. This model compares the costs of distributed generation to the range of usual and customary costs of providing utility service; both peaking and baseload applications are analyzed. The percentage of new load for which distributed generation is more cost-effective than the utility approach represents the market potential (expressed as MW of electric load). The total air emissions from the resulting mix of central and distributed generation is compared to the air emissions that would result if central generation alone were to serve the load growth. The difference between these two levels of air emissions is the net impact from distributed generation.

Second, the economic market potential for distributed generation in the customer sector is determined. Customers' costs of operating distributed generation are compared to the costs associated with buying electric service from the local utility at the prevailing rates. Large industrial customers were considered the most likely candidates for employing distributed generation, with the largest aggregate amount of new electric load that could be served with distributed generation. Seven energy-intensive industries in ten highly industrialized states were used as a sample space, with results extrapolated to a national scale. The total air emissions are calculated, based on the resulting mix of utility generation and customer distributed generation. The difference between this scenario and the central generation only scenario represents the net air impacts from distributed generation in the customer sector.

2. Analytical Methodology

Economic Market Potential Estimation

The goal of this project is to estimate the potential air emissions impacts resulting from the market penetration of distributed generation. The first step toward accomplishing that goal entails estimation of the market potential for *economically viable* distributed generation capacity, expressed in MW/yr of new electric load. This estimate is based on a comparison of the annualized cost to own and operate a distributed generator with the cost to serve that same load with conventional utility central station generation (plus transmission and distribution infrastructure).

For electric utilities, the benefits associated with distributed generation are referred to as the "avoided cost," i.e., the cost that the utility would incur if the distributed generation is not used. The DUVal methodology (proprietary to Distributed Utility Associates) was used to make the estimate (please see details in the paper Introduction to DUVal Methodology [2], and in Section 5 of this report). Simply stated, DUVal compares the cost to implement a particular distributed generation option with the *distribution* of costs to provide service to customers. A utility will be able to serve some customers at lower cost per capita than others, and DUVal identifies the percentage of MW of load for which the distributed generation option is cheaper than the utility generation-and-wires options. (While the authors assumed that generation, transmission and distribution are separately owned, each has a capacity cost; it was also assumed that there will exist an open market for the benefits created by distributed generation owned by any market participant.)

The DUVal-C model is used to estimate the economic market potential for distributed generation for large institutional/industrial electricity users, as described in detail in Section 6. A bill analysis is used: the cost of buying energy from the utility is compared to the cost of producing that energy on-site with distributed generation, and the corresponding percentage of MW for which distributed generation is less expensive represents the economic market potential. Customers in seven industrial categories in ten states are analyzed, and the results extrapolated to the entire United States on the basis of annual total MWh of energy used by the sample space of customers vs. total annual US industrial energy consumption [22].

The second step in the process is to estimate the total yearly air emissions that would result from the mix of distributed generation and utility central generation serving the load growth, and compare that to the total emissions that would have occurred from central generation only serving that load growth. The difference between these two numbers represents the net emissions change expected from the anticipated market penetration of distributed generation.

Emissions Implications of Economic Market Potential

After estimating economic market potential for distributed generators, total air emissions from the cost-effective distributed generators are calculated (based on cost-effective hours of operation and number of MW). To determine emission impacts, each distributed generator's air emissions are compared to those that would have resulted from central generation only. This requires a comparison of total air emissions without adoption of distributed generation to the total air emissions with adoption of distributed generation.

If distributed generation is not economically sound, and thus is not used, all electricity is assumed to be supplied by central generation plants which emit the assumed amounts of the six pollutants per kWh produced (please see Section 4). Air emissions of interest include NO_X, SO_X, CO_2, CO, volatile organic compounds (VOCs) and particulate matter (PM).

If distributed generators are cost-effective, and thus supply some or all of that same electricity, then the overall emissions profile would be different, reflecting an economically efficient mix of central and distributed generation. Air impacts (total change due to adoption of distributed generation) can then be calculated as the difference between emissions given the central-generation-only scenario and total emissions from the central-and-economic-distributed-generation scenario.

Operation of distributed generators in CHP mode also has air emissions implications. Heat from CHP systems is used for processes such as hot water heating, building heat, low pressure process steam, etc. Normally that heat would be produced by burning fuel in a boiler; avoided boiler operation results in reduced air emissions. Only the ATS in customer applications was evaluated with CHP for this study. Please see Section 3 for details of CHP operation.

Note that, for this study, distributed generators were assumed to compete against the "average" power plant, i.e., a composite power plant reflecting the mix of all generator types and fuels used for central power generation nationwide. As with economic market potential estimates, it could be argued that distributed generators would compete against new central generation plants, those that would have to be built in the absence of distributed generation. Newer generation plants (primarily natural gas fired combined-cycle combustion turbines) tend to be cleaner, more efficient, and may or may not have lower cost of production, relative to the existing fleet of generating plants. However, for this study, the assumption was made that enough excess capacity exists in the national generator fleet that distributed generation would compete primarily against it, and not new combined-cycle plants, in the near term (next 10 years).

Distributed Generators Evaluated

For this study only distributed generation technologies were considered. Distributed resources not addressed by this study are:

- non-generation distributed resource options including geographically targeted demand side management (DSM) and energy storage, and
- non-dispatchable distributed generation options including wind turbines and photovoltaics.

Technologies chosen were either:

- considered by the project advisors and authors to be commercially viable, reliable and serviceable, currently or within the next two years; or
- “emerging” options that have great promise as clean electricity sources.

There are literally hundreds of distributed generator systems that could be evaluated. Most of them will be distributed generators that convert liquid or gaseous fuel (usually Diesel fuel or natural gas) into electricity. The most common types of distributed generators are combustion turbines, internal combustion piston-driven engines and fuel cells.

The distributed generation technologies evaluated in this study are described in greater detail in Appendix A.

3. Distributed Generation Cost and Performance

Utility Applications

For the utility portion of the evaluation, a total of six peaking and six baseload distributed generators were evaluated. Cost, performance and emissions for each are shown in Tables 1 – 4.

These data were compiled from a variety of sources. Data for Diesel engines and spark/gas engines were supplied by Caterpillar, Inc. [3]; see Appendix F for details. As the discussion in the Appendix notes, emissions from these types of engines can vary over considerable ranges, due to age, size, manufacturer and emissions technologies installed. The data used in this report resulted from the best estimates of engine performance based on application, size, and expected air regulations.

Data for the Advanced Turbine System (ATS) was supplied by Solar Turbines Corp. [5]. "Conventional" fuel cell data represent currently available phosphoric acid technology and were obtained from the NYSERDA report, 200 kW Fuel Cell Monitoring and Evaluation Program Final Report [6] and from ONSI Corporation [7], a leading fuel cell developer. "Advanced" fuel cells are represented by proton exchange membrane (PEM) technology. Since this technology is still developing, data for this report were compiled by assimilating and reconciling data available from leading developers Ballard Corporation [8] and MC Power Corp. [9], and Joan Ogden of Princeton University, a leading authority in PEM technology. Microturbine data are a composite of data supplied by Allied Signal Power Systems (now Honeywell Power Systems) [10] and Capstone Turbines [11]. These fuel cell and microturbine data were also used in DUA's report to the California Air Resources Board [20].

Notes on the distributed generation data:

1. Emissions data used for internal combustion engines in 2010 reflect limits that will be imposed in future years, and may not be attainable with current technology.
2. Costs used throughout this report are in constant 2001 dollars.
3. A typical utility capitalization structure was used, resulting in a fixed charge rate of 0.15 for distributed generation projects.
4. Customer capitalization structure assumed faster payback and slightly different interest rates than for utilities; the result was a customer fixed charge rate of 0.155.
5. Costs for acquisition of air permits are not included in the analysis; these costs are highly variable and case-specific.
6. Installed costs for actual distributed generation projects are certain to be site-specific, and manufacturers' targets for cost and performance may be optimistic.
7. Fuel cells will have trace amounts of NO_X emissions due to the process used for reforming the natural gas fuel.

Table 1. Peaking Distributed Generation Technologies' Cost, Performance and Emissions, 2002

Distributed Generator Type	Installed Cost $/kW	Installed Cost $/kW-yr*	Heat Rate Btu/kWh	Variable O&M $/kWh	Emissions lb/kWh NO_X	SO_X	CO_2	CO	PM	VOC
Microturbine	475	71.25	12,500	.014	.00125	.00003	1.25	.00285	.000091	.000045
ATS	550	82.50	8,985	.006	.000359	.000021	.95	.000243	.000069	.00003
Combustion Turbine	475	71.25	12,000	.014	.00124	.00003	1.145	.0016	.0004	.00003
Dual Fuel Engine	475	71.25	9,200	.023	.010	.0001	1.2	.0322	.00046	.0009
Otto/Spark Engine	425	63.75	9,700	.027	.00591	.00001	.97	.008	.000475	.0017
Diesel Engine	410	61.50	7,800	.025	.017	.005	1.7	.002	.003	.002

* Utility fixed charge rate of 0.15 is assumed.

Table 2. Peaking Distributed Generation Technologies' Cost, Performance and Emissions, 2010

Distributed Generator Type	Installed Cost $/kW	Installed Cost $/kW-yr*	Heat Rate Btu/kWh	Variable O&M $/kWh	Emissions lb/kWh NO_X	SO_X	CO_2	CO	PM	VOC
Microturbine	400	60.00	12,000	.01	.001	.00003	1.1	.00255	.000045	.00008
ATS	525	78.75	8,985	.006	.000359	.000021	.95	.000243	.00003	.000069
Combustion Turbine	400	60.00	10,500	.01	.0011	.00002	1.0	.00133	.00003	.0004
Dual Fuel Engine	450	67.50	8,600	.02	.005	.0001	1.0	.0291	.0005	.00034
Otto/Spark Engine	425	63.75	9,700	.025	.0026	.00001	.97	.009	.0015	.0003
Diesel Engine	410	61.50	7,800	.025	.017	.005	1.7	.002	.002	.003

* Utility fixed charge rate of 0.15 is assumed.

Table 3. Baseload Distributed Generation Technologies' Cost, Performance and Emissions, 2002

Distributed Generator Type	Installed Cost		Heat Rate	Variable O&M	Emissions lb/kWh					
	$/kW	$/kW-yr*	Btu/kWh	$/kWh	NO_X	SO_X	CO_2	CO	PM	VOC
Microturbine	575	86.25	12,000	.01	.00115	.00003	1.18833	.00265	.00009	.00004
ATS	550	82.50	8,985	.006	.000359	.000021	.95	.000243	.000069	.00003
Combustion Turbine	540	81.00	11,450	.009	.00124	.00003	1.145	.0016	.0004	.00003
Dual Fuel Engine	525	78.75	8,700	.02	.010	.0001	1.20	.0322	.00046	.0009
Conventional Fuel Cell	1,720	258.00	8,530	.015	.000015	.000	.85	.000	.000	.000
Advanced Fuel Cell	1,000	150.00	9,500	.022	.000015	.000	.95	.000	.000	.000

* Utility fixed charge rate of 0.15 is assumed.

Table 4. Baseload Distributed Generation Technologies' Cost, Performance and Emissions, 2010

Distributed Generator Type	Installed Cost		Heat Rate	Variable O&M	Emissions lb/kWh					
	$/kW	$/kW-yr*	Btu/kWh	$/kWh	NO_X	SO_X	CO_2	CO	PM	VOC
Microturbine	475	71.25	11,500	.01	.001	.00003	1.15	.00175	.000083	.00004
ATS	525	78.75	8,985	.006	.000199	.000021	.95	.000243	.000069	.00003
Combustion Turbine	500	75.00	11,150	.008	.0011	.00002	1.0	.00133	.0004	.00003
Dual Fuel Engine	475	71.25	8,500	.018	.005	.0001	1.1	.0291	.00034	.0005
Conventional Fuel Cell	1,100	165.00	8,000	.01	.000015	.000	.82	.000	.000	.000
Advanced Fuel Cell	500	75.00	7,200	.008	.000015	.000	.72	.000	.000	.000

* Utility fixed charge rate of 0.15 is assumed.

Table 5. Customer Distributed Generation Technologies' Cost, Performance and Emissions

Distributed Generator Type	Installed Cost		Heat Rate	Variable O&M	Emissions lb/kWh					
	$/kW	$/kW-yr*	Btu/kWh	$/kWh	NO_X	SO_X	CO_2	CO	PM	VOC
Microturbine	575	89.10	12,000	.01	.00115	.00003	1.18833	.00265	.00009	.00004
ATS	550	85.25	8,985	.006	.000359	.000021	.95	.000243	.000069	.00003
ATS w/CHP**	950	147.25	8,985	.006	.000359	.000021	.95	.000243	.000069	.00003
Dual Fueled Engine	475	73.63	9,200	.023	.010	.0001	1.2	.0322	.00046	.0009
Conventional Fuel Cell	1,720	266.60	8,530	.015	.000015	.000	.85	.000	.000	.000
Advanced Fuel Cell	1,000	155.00	9,500	.022	.000015	.000	.95	.000	.0009	.000

* Customer fixed charge rate of 0.155 is assumed.
**Includes $400/kW capital cost for CHP equipment and installation.

Customer Applications
For the customer applications, the distributed generators listed in Table 5 were used: microturbine, Advanced Turbine System (ATS), ATS with CHP, dual fuel engine, conventional fuel cell (represented by currently available phosphoric-acid technology) and advanced fuel cell (represented by proton exchange membrane (PEM) technology). No distinction between peaking and baseload applications was drawn for customer applications of distributed generation.

Distributed Generation Combined Heat and Power Operation
Most types of distributed generation can provide useful and valuable thermal energy by capturing excess heat produced during electricity generation, and using it to heat water, air, or for process heat. This process is called combined heat and power (CHP).

For energy users requiring substantial amounts of heat, especially industrial, institutional and agricultural operations, CHP can improve the economics of specific distributed generation projects significantly and it can reduce a facility's overall cost of energy considerably.

It was assumed that combustion of fuel to produce heat (usually in a boiler) is typically about 85% efficient. Therefore, each Btu of heat captured from the distributed generator in a CHP process offsets the need to burn about 1.18 Btu of fuel.

For the customer bill analysis the ATS was also evaluated as a CHP generator. Cost, performance and emissions data for distributed generators in CHP mode were developed from manufacturers' data and are representative averages based on the range of typical CHP applications. The incremental cost for CHP is assumed to be $400/kW [5], representing the estimated costs for piping, heat exchangers and engineering associated with CHP installation.

CHP can also yield substantial environmental benefits due to the avoided emissions from boilers. Recouping waste heat from the distributed generator for customer loads (e.g., space or water heating, industrial processes, etc.) can replace the heat produced by burning fuel in a boiler; if the boiler can be replaced by CHP then its emissions are avoided. Nominal values for avoidable boiler air emissions are shown in Table 6; they are based on the leading data source for such information, the U. S. Environmental Protection Agency [12]. (These values are representative of the existing population of boilers which would be the logical candidates for replacement by CHP, and as such are somewhat higher than would be the case for new, more efficient boilers.)

Avoided emissions for each kilowatt-hour of electric generation from CHP are calculated as follows:

$$(((\text{DG Heat Rate} - 3{,}413\ \text{Btu/kWh}) * \text{Waste Heat Recovery Factor}) \div \text{Boiler Efficiency}) \\ * (\text{Pounds of Emissions per Btu of fuel in})$$

Table 6. Avoided Boiler Air Emissions for CHP Operation, lb/$MMBtu_{in}$

	NO_X	SO_X	CO	CO_2	VOC	PM
Nominal	.14706	.00059	.0824	118	.00539	.00745
Best Reported	.03137		.0235			
Poorest Reported	.2745		.0961			

Fuel for Distributed Generators

In this report, the following assumptions apply to the fuels used in the various types of distributed generators:

- microturbine, combustion turbine, Advanced Turbine System (ATS), and spark gas engines all use natural gas fuel
- dual fueled engines run on a combination of natural gas and a small fraction of diesel fuel
- Diesel engines require diesel fuel (at a cost of $4.24/MMBtu)
- fuel cells use natural gas (used with a reformer to generate hydrogen)

In this report, it is assumed that large volume purchases of natural gas will result in a price break compared to small volume gas purchases:

- Natural gas at utility <u>substation</u> locations and for large industrial/institutional electric utility customers is assumed to be high volume purchases; the city gate price of $3.52/MMBtu is assumed for 2002, and $3.61/MMBtu in 2010 [21].
- Natural gas for distributed generators located at or near customer loads (i.e., <u>feeder</u> locations) assumes smaller purchase volumes and thus higher commodity and delivery charges; retail price assumed is $5.60/MMBtu [21].
- Natural gas for large industrial/institutional customer-owned distributed generators was assumed to be $3.52/MMBtu. This price is inclusive of both gas commodity cost and transportation charges and is a 10-year forward-averaged cost [21].

Distributed Generation Assumptions and Caveats

Emissions control technology continues to advance. As a result, many new distributed generators are among the cleanest generating sources available, and continue to improve. New central station generation also benefits from this technology, and existing plants can be retrofitted to improve their performance as well. Therefore, determining the exact emissions numbers to use for a given generating technology is somewhat akin to hitting a moving target. Key factors to consider when deciding which numbers to use are: what is technically feasible, what is cost-effective, and what area- or region-specific emissions regulations apply in a given case.

To illustrate this point, Figure 1 shows NO_x emissions for various distributed generator options, including the ATS, at the time of this study. Note, in particular, that NO_X emissions from the ATS are shown to range from 2.5 ppm to 25 ppm. Achieving 25 ppm NO_X levels from the ATS is routinely attainable today with little modification, and achieving 15 ppm NO_X from the ATS is not difficult with current technology. For this study, ATS NO_X emissions were assumed to be 9 ppm in 2002, and 5 ppm in 2010, reflecting both the ongoing trends in NO_X reduction technologies and the emissions targets that ATS manufacturers expect to meet in those years [5].

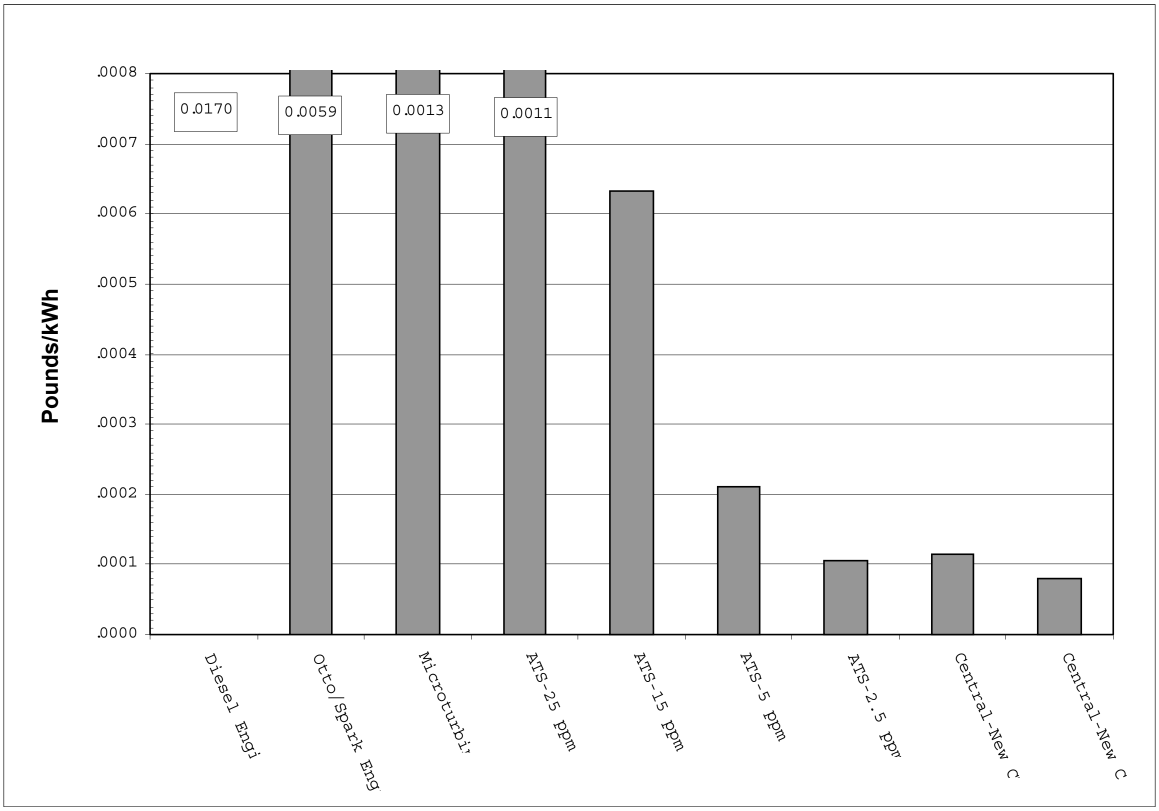

Figure 1. NO_X Emissions from Various Distributed Generators

No attempt was made to reconcile sizes of industrial distributed generators with industrial electric loads. For the most part, this is not an issue because most industrial loads are larger than the typical distributed generator, and most distributed generators are quite modular (though, as unit size decreases, cost does increase relative to unit size). In this context, of special note is the ATS whose nameplate capacity is about 5 MW. If an industrial customer's load is less than 5 MW, then, in order to make a 5 MW ATS installation viable, either excess electric energy and/or capacity is sold to another entity, or two or more customers' loads must be aggregated to 5 MW.

Note: Though natural gas is assumed as the fuel for most distributed generators, natural gas fuel may not be available at all sites.

4. Utility Central Station Generation Cost and Performance

Generation Fuels and Emissions

The utility's cost to generate and/or price to purchase electricity from central generation and air emissions associated with that electricity are highly dependent upon fuels used. Most in-state generation is nuclear, hydroelectric, gas fired and renewables (biomass combustion, geothermal and wind).

Composite emission factors for the mix of major central generation plants within the United States are given in Table 7. These values are estimates derived from EPA data for total 1997 national emissions from utility generation [13] divided by EIA estimates of total 1997 national utility generation [14]. For the purposes of this study, "utility generation" also includes generation from generation companies classified as "non-utility generators."

Table 7. 1997 National Average Central Generation Emissions, lb/kWh

	NO_X	SO_X	CO_2	CO	PM	VOC
Pounds per kWh	.00346	.00743	1.318	.00026	.000172	.000027

Utility Operational and Avoided Cost Assumptions

Peak Load Hours

For this study peak demand hours are defined as a typical summer peaking utility's highest 200 load hours. The significance is that a distributed generator is assumed to provide "peaking service" if it can generate during those 200 hours.

System Load Factor and Annual Load Hours

The annual average load factor is assumed to be 0.545, a figure based on accepted industry guidelines. Annual full load equivalent hours (or full load hours) is 0.545 * 8760 hour per year = 4,774 annual load hours.

Generation Capacity Cost

Generation capacity avoided costs assumed for the analysis are shown in Table 8. These data were compiled from proprietary information used by DUA. The peaking resources reflect a range of costs, from refurbishment or repowering of an existing peaker to purchase of low cost, inefficient combustion turbines (possibly used equipment, to be used for peaking only), with a mean value of $30/kW-yr. The baseload capacity values reflect a range of new power plants: combustion turbine based combined cycle plants and new boiler-based power plants. A triangular probability distribution for these costs is assumed, with a mean of $80/kW-yr.

Transmission and Distribution Capacity Cost

Based on proprietary information compiled by DUA, an average of $27.50/kW-year cost was assumed for distribution capacity needed to serve new electric load, and $9.10/kW-year is assumed as the average cost for transmission capacity needed to serve new load Table 8). Also based on information proprietary to DUA, a statistical distribution is developed for these costs. These are mean values; actual values vary from location to location. DUA uses a statistical representation of that variation.

Electric Energy Cost

The assumed average utility marginal cost for electric energy during peak load hours is 4¢/kWh while annual average or baseload energy costs are assumed to be 2.5¢/kWh [14, 23] (Table 8).

Line Losses

When transmitting electric energy through utility transmission and distribution (T&D) systems the resistivity of wires and transformers leads to losses. These resistive or "I^2R" losses are assumed to be 4% on average throughout the year. In essence this means that to receive 1 kWh at the load requires generation of approximately 1.042 kWh upstream to make up for T&D-related energy losses (1.042 times .96 equals 1.0).

Furthermore, losses are assumed to be higher during peak load hours, affecting "capacity losses" (or reduced ability to carry current). A 6% reduction in load carrying capability is assumed. That means that to get 1 kW of power to the customer during peak demand periods requires about 1.064 kW of generation capacity.

Reliability Benefits Associated with Distributed Generation Use

The value of unserved energy (or value of service) and the total number of hours during the year that a customer cannot be served is a measure of the customers' "cost" of reliability." To the extent that this cost can be avoided by use of a distributed generator, that savings is a benefit that is assumed to accrue to the utility. The U.S. average value of service is assumed to be $3 per kWh "not served," and there are 2.5 hours per year of outages. Therefore, the reliability benefit from use of distributed generators is estimated to be $3 * 2.5 hours = $7.5 per kW-yr. of load [19] (Table 8).

Table 8. Key Central Generation Avoided Cost Values

Base G Capacity ($/kW-yr)	Peak G Capacity ($/kW-yr)	Base Energy ($/kWh)	Peak Energy ($/kWh)	T Capacity ($/kW-yr)	D Capacity ($/kW-yr)	Outages ($/kW-yr)
70 - 90	25 - 30	.025	.04	9.10	27.50	7.5

It is important to note that many utilities do not allow "islanded" operation of distributed generators during grid outages; this type of operation would be required in order for a given distributed generator to receive the reliability credit. Such isolated operation of a distributed generator requires a sophisticated interconnection scheme that protects the utility grid, its customers, and the load served by the distributed generator during transitions from grid to distributed generator power, and vice versa.

Utility Avoided Cost: Caveats and Considerations

As with the economic calculations for this evaluation, it could be argued that distributed generators would compete against new central generation plants that would have to be built in the absence of distributed generation. However, that assumes that distributed generators would only be deployed in situations that offset need for new central supply.

In reality, if distributed generators were deployed, they would probably offset some new central power plant construction as well as some expensive generation from older, less efficient central generators. This is an important point in this context, because new central station combined-cycle generation plants tend to be more fuel-efficient and to produce fewer emissions than the composite of all power plants, including older and less efficient plants.

5. Utility Distributed Generation Market Potential Evaluation

Methodology and Assumptions

Calculation of economic market potential for utility owned and operated distributed generation is based on economic criteria that electric utility planners and engineers would use to evaluate the costs and benefits associated with use of distributed generators. (The PG&E publication RESOURCE: An Encyclopedia of Utility Terms [15] contains a wealth of definitions and additional information for many of the terms used in this analysis.)

As illustrated in Figure 2, to make the economic market potential estimates, the DUVal model [2] compares:

- a statistically defined range of possible annualized avoided cost (i.e., **benefits**) associated with use of the distributed generator

 to:

- the utility's annualized net **cost** to own and operate a distributed generator.

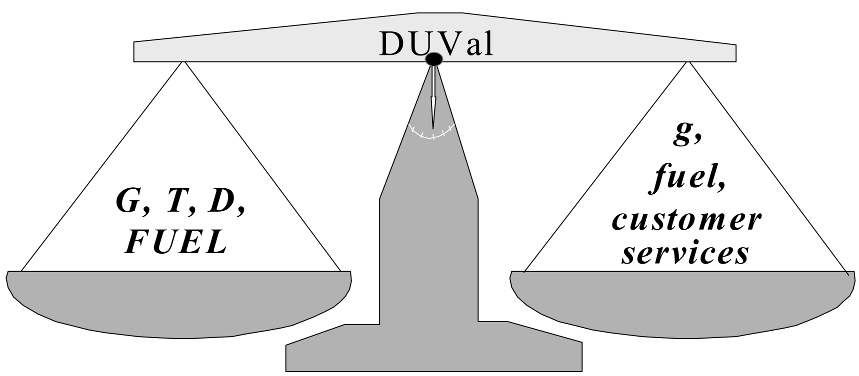

Figure 2. DUVal Evaluation—Utility Perspective

Cost of ownership includes purchase, installation, financing, depreciation expenses, taxes, fuel, maintenance, and fixed costs such as periodic overhauls and insurance.

Utility benefits associated with the use of distributed generators are utility/grid-related costs that will not be incurred by the utility (i.e.; are an "avoided cost") if the distributed generator is used in lieu of the central/grid solution. This assumes, of course, that the distributed generator can provide the same or better service reliability and power quality. In other words, for the utility, the benefit associated with use of a distributed generator is the avoided cost for otherwise needed fuel, O&M and overhead expenses and generation, transmission and distribution capacity (equipment) costs.

(Note that even if a project is merely deferred rather than avoided altogether, the time value of money often makes it worthwhile to use a temporary, redeployable, modular, and less financially risky distributed generation option rather than a more typical grid upgrade.)

Variability of Utility Avoided Cost

The DUVal model uses a statistical representation of the *range* of utility avoided costs throughout the service area and among locations. Utility avoided costs, defined as those costs avoided if distributed generators are used in lieu of the conventional central generation and wires option, vary widely among utilities and even within a given utility's service territory. Some locations are inexpensive to serve and others can be quite expensive to serve. These costs are modeled in DUVal as statistical distributions referred to as "value mountains" because of their characteristic shape (shown in Figure 3).

Underlying assumptions that are used to create value mountains are shown in Table 8. These ranges of values represent the statistical variation of electric utility total avoided costs to meet new load. Components are generation capacity and generation variable costs, transmission and distribution facilities, and outages. These are costs associated with serving new load (i.e., "load growth").

Avoided costs for generation, transmission, and distribution capacity to serve new load are parameters that are assumed to vary, resulting in the variation that underlies the value mountain as shown in the example in Figure 3. The range of costs for utility baseload and peaking generation are modeled as a "triangular distribution" of costs whose high and low values are shown in Table 8. T&D capacity costs vary from one location to another in a more complex manner. These data ranges were derived from recent historical utility data in the Energy Information Administration's Electric Power Annual, 1997 [14].

Determination of Economic Market Potential

The total cost to implement a distributed generation option is compared to the value mountain of avoided costs. The economic market potential for a given distributed generation technology corresponds to the total number of locations that are more expensive to serve with central generation than with the distributed technology being analyzed.

Economic market potential is expressed in percent of the total market (total market in this context being the technical market potential, or, all MW/year of load in play, described in the next section of this report).

In the example, consider point **a**; assume it indicates the cost (in $/kW-yr) to own and operate a distributed generator. Point **b** indicates the portion of utility avoided cost that is higher and lower than that for the distributed generator being considered. Point **c** indicates the economic market potential—the portion of load growth for which the distributed generator cost is lower than the grid solution composed of central generation and T&D enhancement. In the example the distributed generator's cost is lower than about 29% of the situations, statistically speaking. If load growth was 1,000 MW, then the economic market potential is 290 MW.

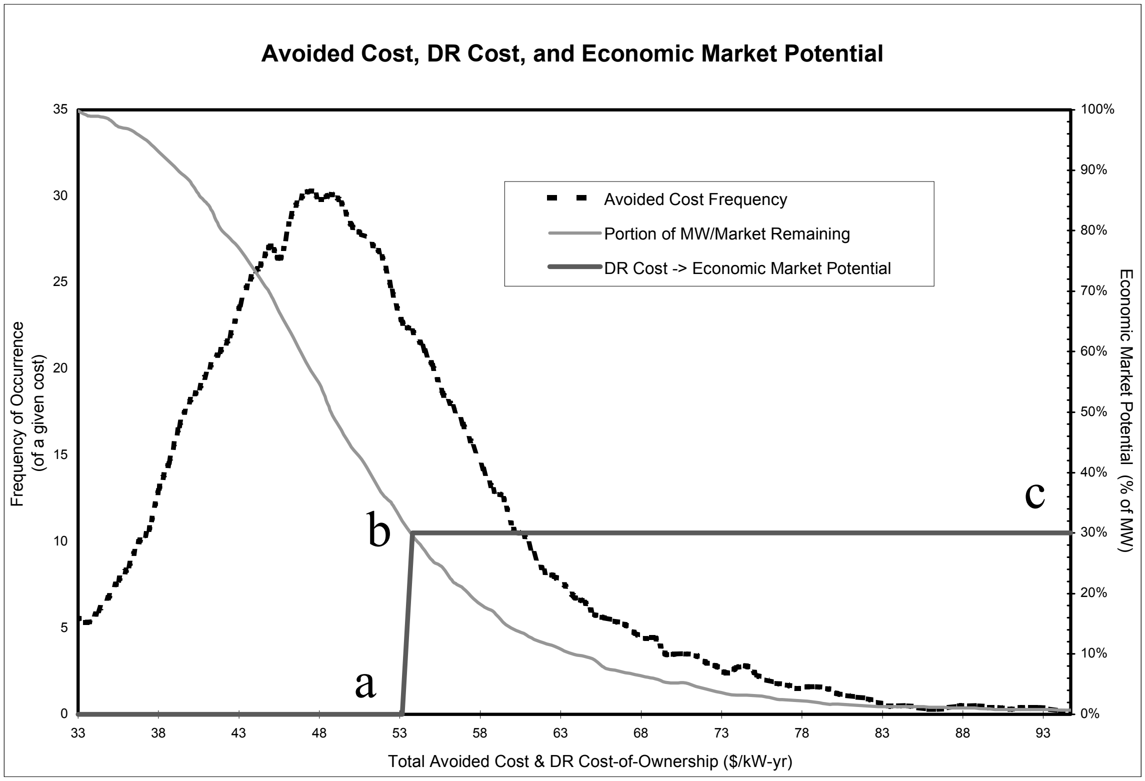

Figure 3. Statistical Spread of Utility Total Avoided Cost and Economic Market Potential ("Value Mountain")

Utility Operational Modes: Peaking and Baseload

Quantitative economic market potential estimates are made for both peaking and baseload operation modes. The distributed generation is assumed to be sited at substation and feeder locations (i.e., at or near loads), thereby capturing the benefit of avoided transmission and distribution costs.

To serve as a **peaking** resource, a distributed generator must reduce utility infrastructure capacity needs. That, in turn, requires distributed generation to be operational during the utility's peak demand hours: the 100 to 200 hours during the year when demand for electricity is highest. The level of power draw on the utility system from all customers during those times dictates the required maximum capacity of the utility's generation system.

This concept is important for the analysis because the degree to which a distributed generator allows the utility to avoid procurement of additional capacity determines the "capacity benefit" associated with distributed generation. Stated another way, to the extent that distributed generators operate to offset the need for new/upgraded utility electric grid capacity, they receive a capacity credit commensurate with the amount of otherwise needed utility generation, transmission and/or distribution equipment (capacity, infrastructure). Note that because peaking distributed generators operate for so few hours per year, their total variable operating costs in the evaluation are much less than their total capital costs.

Baseload distributed generators operate for thousands of "full load equivalent" hours per year, in this case about 4,700 hours. They can also receive the capacity credit described above if they generate during the utility's peak demand hours. But for baseload distributed generators, it is usually more important to consider their cost of production for electric or thermal energy.

Because they operate for many hours per year, baseload distributed generators must compete primarily on an "energy" (i.e., variable) cost basis. (By contrast, the key criterion of merit for peaking units is "capacity" cost, a fixed cost.) During most of the year, the competition for baseload distributed generators is lower-cost commodity electricity from the wholesale electric marketplace. That marketplace is dominated by large generation facilities with economies of scale and generally low incremental cost of production.

Therefore, installed capital cost and cost of production are both key criteria driving a baseload distributed generator's economic competitiveness. In turn, a baseload distributed generator's net cost of production is driven by fuel efficiency, fuel price, variable operations and maintenance costs for the particular distributed generator, and the degree to which waste heat can be sold for cogeneration.

Utility Locations: Substation and Feeder

As depicted graphically in Figure 4, DUVal evaluates distributed generators at two location types: at a utility substation and on a distribution feeder at or near a customer's site.

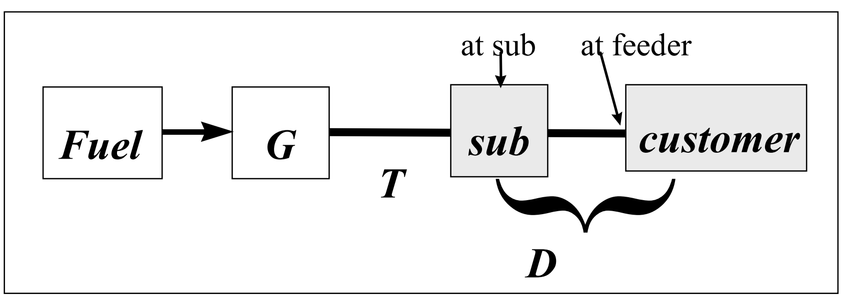

Figure 4. DUVal Evaluation Nodes

Several factors distinguish these two types of locations; key ones are:

- Because most electric service outages occur between the substation and the load, a distributed generator sited at the substation does not receive as substantial a credit for reliability increases as does a distributed generator located on the feeder or at the customer's site.

- Distributed generators at substations do not defer the need for a feeder and thus do not receive an avoided cost credit for the cost of a feeder.
- Distributed generators at a substation are assumed to be larger and to qualify for purchase of gas at a wholesale/power plant procurement price; distributed generators on the feeder are assumed to use gas whose prices are higher because purchases are at a lower-volume, "retail" level.

It is assumed that the required fuel type and distribution infrastructure are available at all sites considered.

Utility Evaluation MegaWatts "In play"

The maximum potential size of the market (technical market potential) for distributed generation is assumed to be the total load growth in units of MegaWatts per year (MW/year) – the MegaWatts "in play" each year. For this study, average coincident peak load growth nationwide is 13,639 MW/yr (13.6 GW/yr) in 2002 and 13,852 MW/yr (13.8 GW/yr) in 2010 [23]. To translate these figures to distributed generation peak capacity, a factor of 1.6 is applied. This reflects the fact that distributed generation will be serving non-coincident loads in the distribution system, rather than coincident loads as seen by central generation. The 1.6 factor is based on DUA's experience in estimating this relationship. Therefore, the amount of distributed generation market potential is estimated to be 21,822 MW/yr in 2002 and 22,163 MW/yr in 2010.

Note that no "embedded" load is considered to be in play; only the annual increase in total load (load growth) is assumed to be in play. This is reasonable because it is unlikely that existing capacity with a useful life will be removed or decommissioned.

Utility Distributed Generation Economic Market Potential and Emissions Impacts

Peaking Mode Distributed Generation Results

Economic Market Potential and Emissions Implications

Evaluation results for peaking distributed generators are shown in Tables 9 and 10, for the years 2002 and 2010, respectively; the percentage of load growth for which the given distributed generation technology is cost-effective is found in the columns labeled "Portion of Growth." The first data row in each table, labeled "System Only," represents the case in which all load growth is served by existing central generation, i.e., no distributed generation is installed. The following six data rows show the total air emissions that would result from the mix of generation: cost-effective distributed generation at the market share shown, plus power supplied by the grid for the balance of the load growth. Each technology is evaluated against central generation only, and not against other technologies.

Emissions are stated in thousands of tons per year. It is helpful at this point to remember that emissions due to peak load operation are for production of electricity needed to serve load added within the given year, i.e., for load growth (also referred to in this study as "load in play"). Furthermore, emissions are for generation during 200 peak load hours in a year.

Table 9. Peak Load Central and Distributed Generation Economic Market Potential and Air Emissions, 2002

2002 Peaking Distributed Generator Option	Portion of Growth (%)*	Emissions - Thousands of Tons					
		NO_x	SO_x	CO_2	CO	PM	VOC
System Only	100.0	7.78	16.7	2966.0	0.58	0.39	0.06
Microturbine	31.5	6.19	11.4	2891.0	2.36	0.33	0.08
Adv. Turbine System (ATS)	68.8	2.97	5.25	2351.7	0.55	0.22	0.07
Conv. Combustion Turbine	32.5	6.13	11.3	2814.1	1.53	0.29	0.06
Dual Fuel Engine	35.1	12.7	10.9	2844.1	25.0	3.31	0.73
Otto/Spark Engine	51.5	10.4	8.12	2528.7	9.27	0.72	1.94
Diesel Engine	73.8	29.4	12.4	3514.9	3.37	4.93	3.24

* Load growth = 21,822 MW/yr

Table 10. Peak Load Central and Distributed Generation Economic Market Potential and Air Emissions, 2010

2010 Peaking Distributed Generator Option	Portion of Growth (%)*	Emissions - Thousands of Tons					
		NO_x	SO_x	CO_2	CO	PM	VOC
System Only	100.0	7.90	17.0	3012.4	0.59	0.39	0.07
Microturbine	67.1	4.09	5.63	2626.9	3.99	0.25	0.09
Adv. Turbine System (ATS)	77.7	2.11	3.82	2307.7	0.55	0.21	0.07
Conv. Combustion Turbine	72.4	3.95	4.72	2436.0	2.30	0.17	0.07
Dual Fuel Engine	49.1	9.46	8.75	2621.5	32.0	4.55	0.58
Otto/Spark Engine	53.4	7.19	7.92	2551.8	10.9	0.54	1.81
Diesel Engine	74.5	23.5	12.6	3575.1	3.45	0.93	3.32

* Load growth = 22,163 MW/yr

Peaking distributed generation technologies appear to be cost-effective for substantial portions of new load in both years studied. For example, in 2002, the microturbine is cost-effective for 31.5% of the market, about 6,874 MW. The diesel engine has a market share of about 73.8% (16,105 MW). The other four distributed generator options lie between these two; notable among these is the Advanced Turbine System (ATS) at 68.8% market share (15,014 MW). In 2010, improvements in cost translate into increased market shares for all technologies, especially the microturbine and combustion turbine. Figures 5 and 6 show the market potential in MW for peaking distributed generators in 2002 and 2010, respectively.

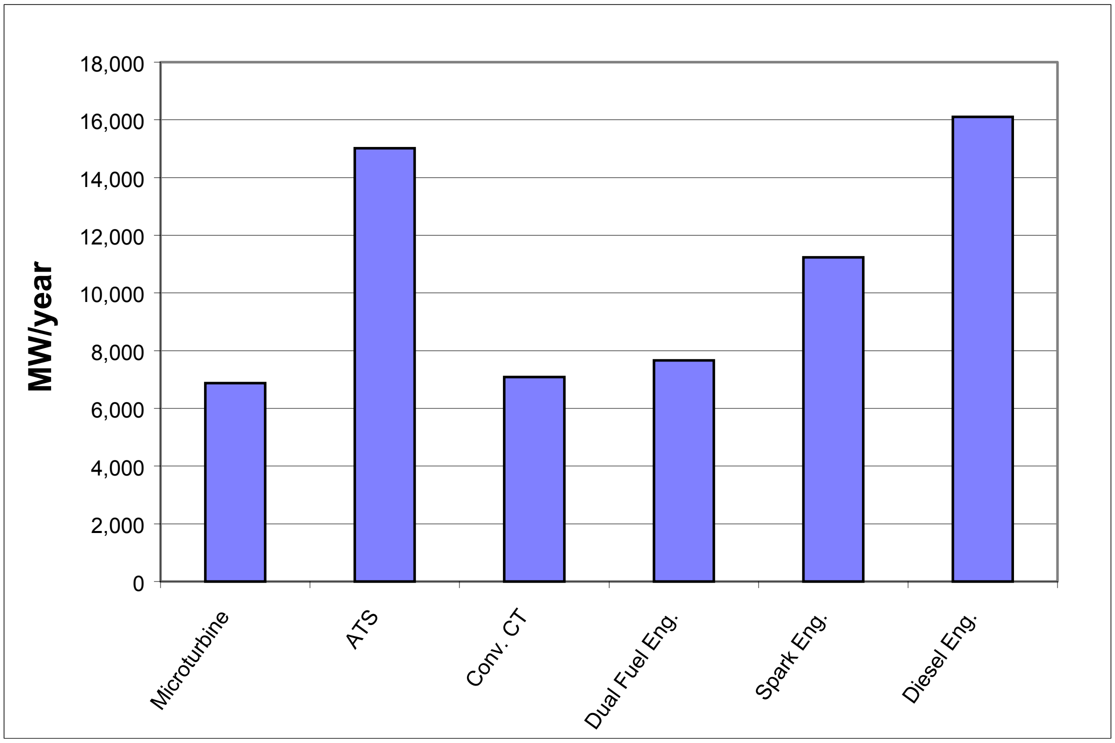

Figure 5. Utility Peak Distributed Generation Market Potential in 2002, MW/yr

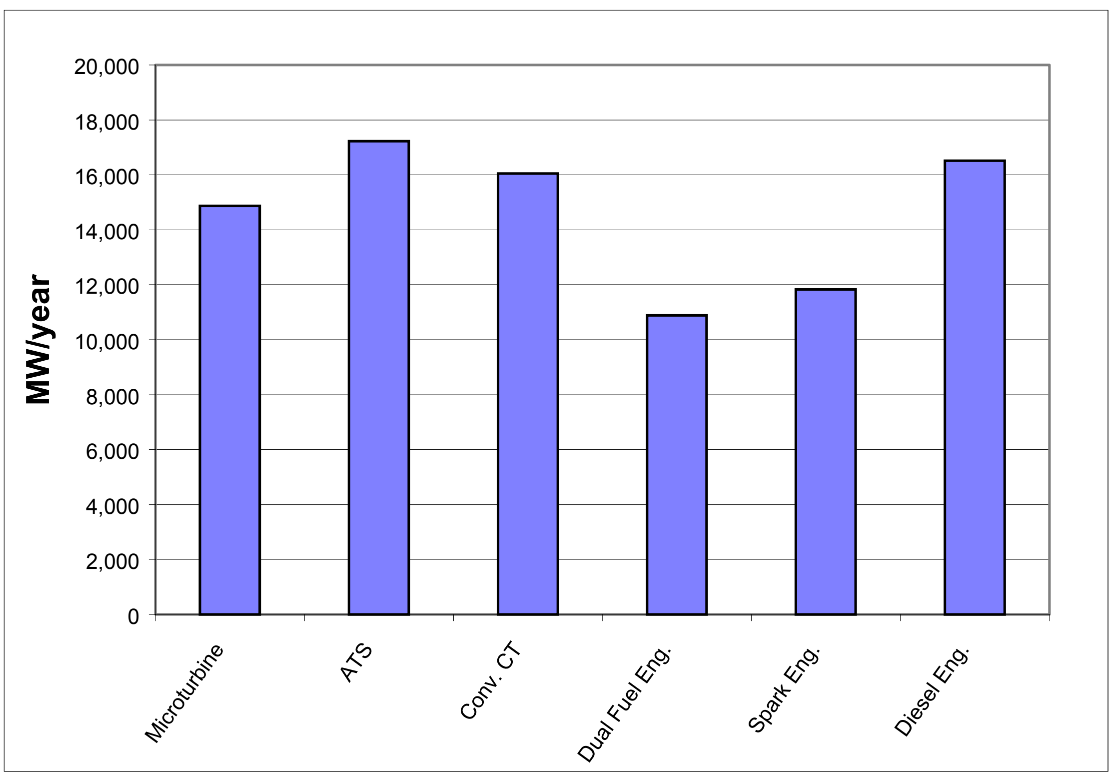

Figure 6: Utility Peak Distributed Generation Market Potential in 2010, MW/yr

If these levels of market potential are achieved, in 2002 the three turbine-based technologies would result in reduced levels of NO_X, SO_X, and CO_2, and virtually no change in particulates (PM) and volatile organic compounds (VOC); CO increases for the microturbine and combustion turbine, but decreases for the ATS. The three engine-based technologies would result in generally increased levels of NO_X, CO, PM and VOC and reduced levels of SO_X; CO_2 increases for diesels and decreases for dual fuel and spark engines.

Baseload Mode Distributed Generation Results

Economic Market Potential and Emissions Implications

Estimated economic market potential and emissions for utility baseload distributed generators is given in Tables 11 and 12, for the years 2002 and 2010, respectively. Values in the first data column are the economic market share estimates for each distributed generator type, expressed in per cent of the load growth for that year. Values in the remaining columns are the air emissions, in tons, that would result from the generation mix specified by either: central generation only (first row), or distributed generation technology at the specified market portion plus central generation for the balance of the load growth. Note: Each technology is evaluated against central generation only, and not against other technologies.

Table 11. Baseload Central and Distributed Generation Market Potential and Air Emissions, 2002

2002 Baseload Distributed Generator Option	Portion of Growth (%)*	Emissions - Thousands of Tons					
		NO_X	SO_X	CO_2	CO	PM	VOC
System Only	100.0	185.8	398.9	70,802	13.8	9.22	1.54
Microturbine	0.0	185.8	398.9	70,802	13.8	9.22	1.54
Adv. Turbine System (ATS)	2.7	181.2	388.2	70,227	13.8	9.07	1.54
Conv. Combustion Turbine	0.1	185.6	398.5	70,791	13.9	9.23	1.54
Dual Fuel Engine	0.1	186.1	398.5	70,794	15.5	9.24	1.58
Conventional Fuel Cell	0.0	185.8	398.9	70,802	13.8	9.22	1.54
Advanced Fuel Cell	0.0	185.8	398.9	70,802	13.8	9.22	1.54

* Load growth = 21,822 MW/yr

As Table 11 indicates, distributed generation technologies have a hard time competing with baseload central generation in 2002: market potential is virtually nil, with only the efficient ATS capturing a meager 3% or so of the market applications, or about 589 MW. The impact on emissions levels is correspondingly small, as well. The situation is not materially different in 2010 (Table 12), with one notable exception: the advanced fuel cell. Due to projected advances in cost and efficiency by 2010, the advanced fuel cell could capture about 51% of the baseload market (about 11,325 MW), with substantial reductions in all air emissions categories.

Table 12. Baseload Central and Distributed Generation Market Potential and Air Emissions, 2010

2010 Baseload Distributed Generator Option	Portion of Growth (%)*	Emissions - Thousands of Tons					
		NO_X	SO_X	CO_2	CO	PM	VOC
System Only	100.0	188.7	405.2	71,908	14.0	9.37	1.56
Microturbine	0.0	188.7	405.2	71,908	14.0	9.37	1.56
Adv. Turbine System (ATS)	2.3	184.6	395.9	71,410	14.0	9.23	1.56
Combustion Turbine	0.0	188.7	405.2	71,908	14.0	9.37	1.56
Dual Fuel Engine	0.0	188.7	405.2	71,908	14.0	9.37	1.56
Conventional Fuel Cell	0.0	188.7	405.2	71,908	14.0	9.37	1.56
Advanced Fuel Cell	51.1	92.7	198.1	54,628	6.9	4.58	0.76

* Load growth = 22,163 MW/yr

Market potential in MW for utility baseload distributed generation in the years 2002 and 2010 is shown graphically in Figures 7 and 8, respectively.

Utility Baseload Distributed Generation Results and Observations

As a brief review: baseload distributed generators operate during the utility's load hours; in this evaluation, that represents the 4,774 "full load equivalent" hours during the year when virtually all demand for energy occurs.

As discussed above, baseload distributed generators' cost-effectiveness is a function, in part, of their ability to provide electric <u>capacity</u>, when needed. But to be viable, the baseload distributed generators must also generate <u>energy</u> needed over 4,774 full load equivalent annual load hours at a competitive cost. So a baseload distributed generator is cost-effective if it can provide <u>both</u> capacity and energy at a competitive total cost relative to the grid.

Stated another way, distributed generators are deployed by utilities for one or both of two primary benefits:

1) to allow the utility to avoid costs related to adding utility generation, transmission, or distribution equipment/infrastructure (i.e., capacity), and/or

2) to provide cost-competitive energy (primarily electric energy but possibly including mechanical and thermal energy), resulting in reduced overall cost-of-service, and possibly reduced net fuel use and net air emissions.

Note that baseload distributed generators tend to be deployed at substation locations. That is due to the fact that natural gas price is assumed to be significantly higher for feeder locations than for substation locations, for a variety of reasons. Note also that the fuel price advantage at substation locations can be offset, to some degree, by the fact that

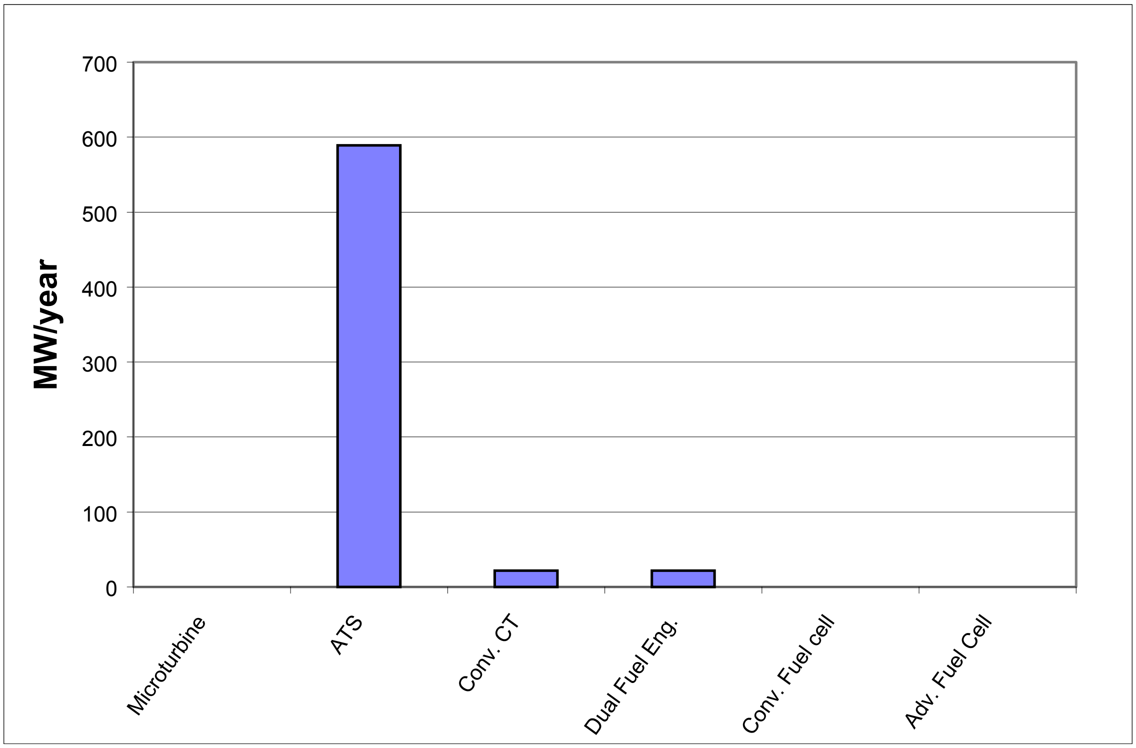

Figure 7. Utility Baseload Distributed Generation Market Potential in 2002, MW/yr

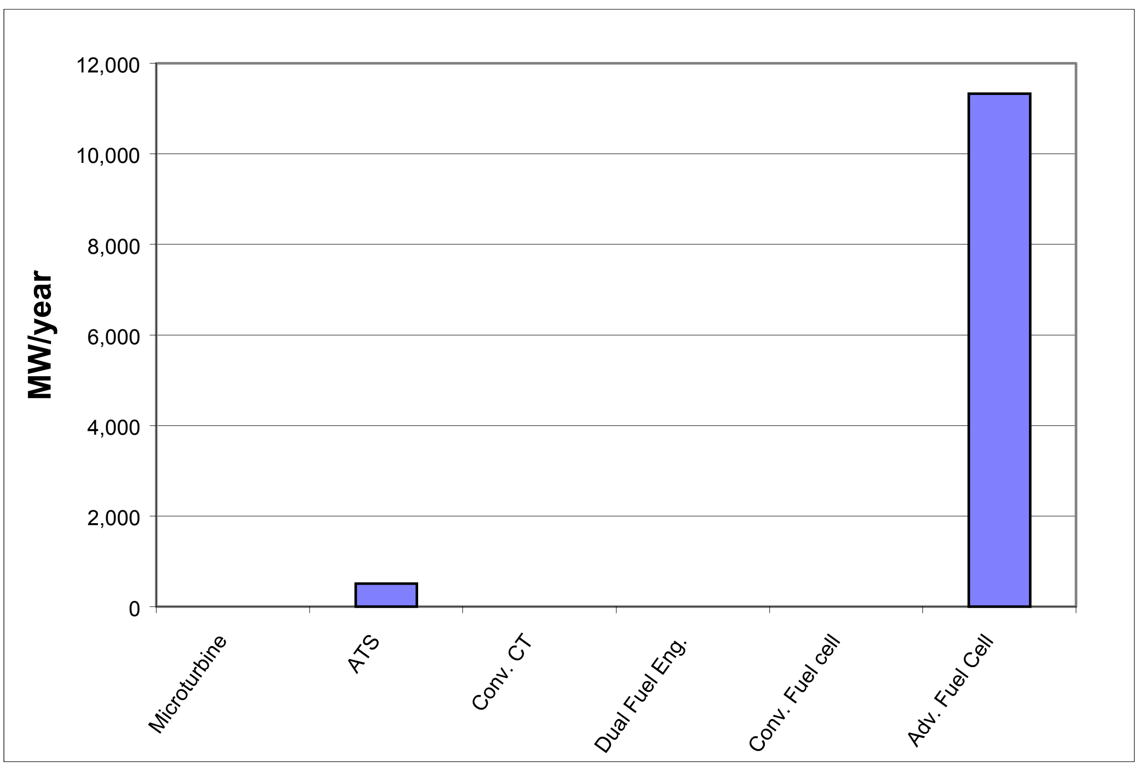

Figure 8. Utility Baseload Distributed Generation Market Potential in 2010, MW/yr

distributed generators located at substation locations are farther from loads than feeder distributed generators (i.e., they are upstream from most outages) and thus they provide much less of a reliability improvement benefit. The one important exception to the fuel cost advantage is when distributed generators are used in CHP applications. CHP can only occur at feeder locations, where demand and thermal loads are. CHP is cost-effective if the incremental cost to recover the heat is less than the price that would have been paid to generate the same heat with natural gas.

Utility Distributed Generation Results: Observations

- In an absolute sense, because utility peaking distributed generators would only operate for 200 hours per year and would only address new load (that from load growth), installation of most or all types of peaking distributed generators would add much lower amounts of emissions than baseload distributed generators.
- Diesel engines are the lowest-cost distributed generation option, therefore they are very cost-effective capacity resources for applications requiring limited hours of operation.
- Distributed generation technologies are generally not cost-effective for baseload applications, except for the advanced fuel cell in later years when capital costs and efficiencies reach their anticipated target levels.

Utility Distributed Generation Results: Caveats

- Economic market potential estimates are calculated without regard to substitutes. In actuality distributed generators would have to compete against other distributed generators and possibly energy storage, demand side management (DSM) or other conservation resources.
- Electric utility ownership of distributed generation may be prohibited or restricted in some cases, depending on local regulation.
- For gas fired options, economic market potential values may be reduced based on the availability (and cost) of natural gas fuel at specific locations.
- Economic market potential for peaking and baseload distributed generators were evaluated as solutions for the same "market," that is, all of the forecasted electric load growth. In reality, of course, these are very different applications or market segments with very different needs and decision drivers. Peaking units primarily offset expenditures for fixed capital equipment; baseload distributed generators are used because they result in both reduced need for capital equipment (upstream to bolster the electric grid) and lower overall energy production cost, usually due to lower variable maintenance costs and/or lower fuel cost per kWh produced than for grid-based electricity. Also note that, at some point, these two market segments will begin to overlap.

The following caveats are important as readers consider the results for electric utility owned peaking distributed generators:

- Substantial deployment of diesel fueled engines may be problematic because of air emissions.
- Non-generation options, such as geographically targeted conservation, demand side management (DSM), or energy storage, may indeed be cost-effective in some situtations for peaking applications. If so, they would compete against generation options evaluated for this study.

The following additional caveats are important to keep in mind when considering the results for baseload generators:

- Substantial deployment of dual fueled engines may be problematic because of air emissions, especially NO_X.
- If electric utility ownership of distributed generators is restricted, it is likely to be based on the amount of energy generated rather than the amount of capacity added. This may make baseload distributed generators unattractive despite being cost-effective in a strictly financial sense.

6. Customer Evaluation and Bill Analysis

Methodology and Assumptions

Methodology Overview

The customer bill analysis was undertaken using DUA's DUVal-C model. It minimizes the annual cost incurred by an electric utility customer to serve a given kW of electric load. The bill analysis is a comparison of the cost to purchase all electricity versus the cost to own and operate a distributed generator to generate some or all of the electricity needed. The concept is illustrated in Figure 9.

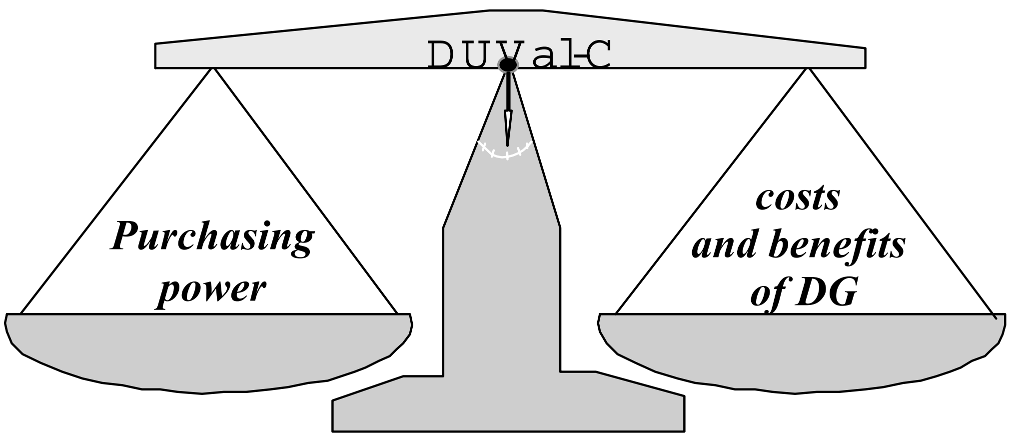

Figure 9. DUVal-C Evaluation

In other words, some or all electricity may be purchased either from the electric utility or customers may produce equivalent (or better) electricity on-site with distributed generation. The "make-or-buy" decision is made by first calculating the annualized costs of the two options (utility service or distributed generator ownership and operation), and then estimating the portion of customer load hours for which distributed generation is cost-competitive.

Cost for both options, *make* (use distributed generation) or *buy* (purchase from utility), are calculated with consideration given to a wide range of customer decision criteria, mostly financial. Key criteria include cost of capital (for financing the distributed generator), payback period required, electric service outage costs, and the reliability of both the grid and the distributed generation technologies.

The project scope of work specified that the net emissions from the market penetration of distributed generation were to be analyzed for the "Vision Industries" designated by the U. S. Department of Energy's Office of Industrial Technologies (OIT) [22]. The approach called for a sampling of 10 states, with sizable sales activity (and corresponding energy consumption) in the seven industries of interest, which would provide sufficient "coverage" to yield a statistically valid sampling. "Sufficient" is taken to mean about 50% of the national total in any given industrial category. This sampling could then be extrapolated nationally with reasonable accuracy, by using the ratio of electric load in the 10 selected states to the ratio of total electric load nationwide.

Key Parameters and Assumptions

The data set required for a bill analysis is comprehensive. Categories of inputs include:

- customer financials, such as cost of capital, tax rates, depreciation schedules, etc.
- electric energy price and demand charges for each of three time periods (on-peak, mid-peak, and off-peak) for each of twelve months (a total of 36 utility electricity "price periods" within the year)
- customer electric energy use and peak demand for power during each of the 36 price periods
- fuel prices and availability
- distributed generator parameters: equipment cost, fuel efficiency, O&M costs and emission factors
- electric load and energy use that can be served by distributed generators (i.e., CHP potential)

Customer Financials

DUVal-C uses an annuity representation of the carrying cost for the capital equipment. That annualized cost is a function of the cost for the equipment, customer federal and state income tax rates, customer cost of capital (that is, in turn a function of debt interest rate, and return on investment for non-debt capital), and depreciation. (See also the DUA report to the National Renewable Energy Laboratory [16] and the report to the California Air Resources Board [20]).

For this study, the customer uses 50% debt financing with a 9% per year interest rate and 50% owner financing requiring a 20% return. The Federal income tax rate is assumed to be the marginal rate of 34% and the state tax rate is the marginal rate of 8.8%. The equipment is depreciated over five years for tax purposes, and the operational life is assumed to be 10 years.

The result is a fixed charge rate of 0.155 (annualization factor). It is used as follows: For a distributed generator whose installed cost is $500/kW, the annual "carrying cost" associated with financing and depreciation of distributed generator <u>equipment</u> is $500 * 0.155 = $77.50/kW-year. This represents the annual cash outlay to finance and depreciate the distributed generator equipment; it does not include any variable costs associated with the operation of the plant, such as fuel or maintenance.

Utility Prices and Price Periods

A key consideration for the bill analysis is the utility price for electricity. Primary components are: 1) price for electric energy, reflecting utility variable cost incurred to generate electricity, comprising mostly fuel and O&M expenses; and 2) demand charges reflecting the utility's fixed costs for delivery of electricity.

Underlying the customer's electric utility bill are the rates or tariffs that specify the prices charged for energy and demand. Energy prices are denominated in units of $/kWh and apply to each kWh used by the customer. Demand charges are typically specified in units of dollars per kW per month ($/kW-mo), and are applied to the maximum customer demand for power (units of kW) during the month.

Energy price and demand charges can vary according to the time of day and the month. Therefore electric energy price is specified for each of three time periods (on-peak, mid-peak and off-peak) for each of twelve months (a total of 36 "price periods" within the year). Peak demand charges are specified for on-peak and mid-peak price periods for each of twelve months.

On-peak electric energy is used by consumers during times when a utility's electricity production is greatest, usually during afternoon hours on hot summer days and during the early evening hours on cold winter days. It is more expensive than the average price for electricity (and for off-peak electric energy) because peaking power plants, as a class, tend to be less efficient and their non-fuel operating costs, especially for O&M, higher than baseload plants.

Mid-peak and off-peak electric energy from the utility is less expensive because more fuel-efficient baseload generators generate it. Thus, the price tends to be lower than for on-peak electricity. Many baseload generators also have lower non-fuel operation and maintenance costs than peaking generators. In some cases, the price for off-peak utility electricity is affected by the fact that many generators are designated as "must run" units. A generator could be designated "must run" for any of several reasons, including: 1) transmission system operation constraints, 2) it is not economic to reduce plants' power output below certain levels, or 3) it is not practical to shut them down altogether for just a few hours because of the cost and extra wear and tear associated with restarts. The availability of low-cost power from baseload utility plants during off-peak, and possibly mid-peak, price periods helps to keep average annual prices low.

Demand charges address <u>fixed costs</u> incurred by the utility for plant and equipment required to supply electric energy to end-users. (By contrast, the price for electric *energy* reflects the utility's <u>variable expense</u> to generate the electric energy, mostly fuel for fossil fueled plants.) This capacity (and electric demand) is expressed in units of power (kW).

Each large customer's peak demand (<u>maximum</u> power draw) is measured each month. A demand charge ($/kW-month) is applied to each unit of <u>maximum</u> electric demand (kW) that occurs within each demand price period. (Price periods vary by time-of-day and by month). If distributed generators operate during periods when the demand charge applies, the customer can minimize the demand charges, which is a benefit in the bill analysis context.

Electric rates for the ten states used in the customer analysis were obtained from the publicly available utility tariffs in place at the time of this study.

Customer Electricity Use: Amounts and Timing

Customer loads are assumed to have a 0.8 annual average electric load factor, i.e., energy use occurs, on average, 80% of the time during a year (a measure of the rate of energy use for each kW of load connected).

As noted above, customer demand (peak kW) and electric energy (kWh) use vary during the year. During hours of peak operation, a facility's electric demand and the rate of electric energy use is at a maximum. During "off peak" hours (e.g., during weekends and late at night) the maximum hourly demand is often considerably lower than the facility's peak hourly power draw as is the average rate of energy use.

Fuel Prices

Fuel for distributed generation will be obtained from the local gas utility or from fuel suppliers. Natural gas price is determined by the amount purchased. For this evaluation, the customer is assumed to be eligible for city gate prices, as described in <u>Fuel for Distributed Generators</u> in Section 3.

State Selection and Customer Category Analysis

The dollar figures for industrial-sector total energy expenditures, and for sales in seven categories of major industries, were obtained from the DOE/OIT report, "Turning Industry Visions Into Reality: OIT Accomplishments By State," February, 1997 [22], and are given in Tables 13 – 23. The seven industry categories of interest were: aluminum, chemicals, forest products, glass, metal casting, petroleum refining, and steel. Table 14 is an alphabetical listing by state, summarizing the information from the report. The data for energy cost was obtained from the Energy Information Administration report <u>Electric Power Annual 1997, Volume I</u> [14]. The total industrial-sector energy expenditures for all 50 states is $103.6 billion. The total sales for all 50 states in the seven industrial categories of interest is $438.5 billion.

As a working hypothesis, the ten states that had the greatest industrial energy expenditures were chosen as the initial sample space (see Table 15, which ranks states by total energy sector expenditures); these states also had fairly healthy sales figures across the categories. They were: Texas, California, Ohio, Louisiana, Pennsylvania, Illinois, Michigan, New York, Indiana, and Tennessee. The questions then are: Have we selected the "best" ten states for the purpose of evaluating emissions impacts due to distributed generation in the customer sector? Is the "coverage" (i.e., the percentage of the national total represented by these ten states) adequate? Or, are there states other than the ones initially chosen that would add value?

Table 14 shows that the top ten states account for 55.8% of the national total in industrial energy expenditures. Table 15 sorts the states by average industrial electricity rate in

¢/kWh; the ten selected states rank broadly across the middle of the energy cost spectrum, from a low of 3.93 ¢/kWh to a high of 6.97 ¢/kWh.

In Tables 16 through 22, the states are sorted by volume of sales in each of the seven industrial categories; in Table 23 the states are ranked by total industrial sales, i.e., the sum of the seven categories for each state. From these tables one can acquire a qualitative sense of how many of the selected states continue to place near the top of these categories across the board. In each table, the last figure in the percent column represents the percentage of the national total for the ten selected states, in that industrial category.

There is better than 50% representation in all categories except forest products, which is only 35.4%. The forest products category could be improved slightly (i.e., by a percentage point or so) by including a state with a larger forest products total, such as Wisconsin, Oregon or Georgia; unfortunately, because these three states rank relatively low in most other industries, substituting one of them would hurt totals in other industrial categories. It was therefore concluded that the ten states selected gave industrial energy "coverage" that met with the study goals, with the exception of forest products. Extrapolating the results to national totals carries the caveat that the forest products category might have a slightly higher margin of error, in terms of interpreting the impacts on air emissions.

Thus, for each of the ten selected states, the potential market penetration for distributed generation technologies on the customer side was determined, in both 2002 and 2010; both peak load applications and base load applications were considered, and the effects of applying economic penalties based on air emission was included. The estimated net change in total air emissions for the ten states could then be calculated, and extrapolated to national estimates.

Customer Benefit/Cost Evaluation

As described above, a bill analysis is a comparison of the cost to purchase some or all electricity from the utility grid, versus the cost to own and operate a distributed generator to provide comparable service. The decision to make or buy is made by comparing annualized cost for the two options to estimate the portion of customer load hours for which distributed generation is cost-competitive.

The make or buy decision is based on month-specific time-of-day prices for electricity from the grid. For each of three daily price periods in each of twelve months (i.e., 36 price periods per year) DUVal-C chooses the lower of:

- the cost to make power using an on-site distributed generator,

or

- the cost to buy power from the grid to meet electricity requirements

If, during a given price period the incremental/variable cost of production for the distributed generator is lower than the equivalent power from the grid, then the

Table 13. 1996 Energy Costs and Industrial Sales (DOE/OIT)

State	Energy Data		Industrial Sales - $Millions							
	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Aluminum	Chemicals	Forest Products	Glass	Metal Casting	Petroleum Refining	Steel	Total
Alabama	2,394.9	3.91	1,719	4,910	9,533	0	1,083	1,223	1,962	20,430
Alaska	175.1	8.47	0		504	0	0	1,045	0	1,549
Arizona	928.4	5.19	2,533	1,069	1,199	0	28	59		4,888
Arkansas	1,178.2	4.47	994	1,762	5,859		163	744	818	10,340
California	7,094.7	6.97	1,302	16,417	14,381	1,212	903	18,775	2,158	55,148
Colorado	721.9	4.35		599	796		11	754	279	2,439
Connecticut	815.3	7.86	1,007	3,858	1,656		26	172	459	7,178
Delaware	305.9	4.68		2,803	588	0	0		120	3,511
Florida	1,929.1	5.11	239	6,668	5,442	166	71	310	386	13,282
Georgia	2,644.5	4.29	2,006	6,752	11,988		222		477	19,168
Hawaii	387.0	10.03	0	73	40	0	0		0	113
Idaho	455.9	2.68	0	978	1,999	0	0	0	0	2,977
Illinois	4,942.6	5.24	2,302	17,133	6,632	389	1,128	9,241	4,641	41,466
Indiana	3,627.2	3.93	3,612	10,023	4,847	371	1,499	4,234	9,163	33,749
Iowa	1,331.1	3.91		3,396	1,244	0	321	71	142	5,174
Kansas	1,351.4	4.70		2,083	1,150		123	3,111	0	6,467
Kentucky	2,105.8	2.92	1,627	5,463	2,701	213	214		1,327	11,545
Louisiana	5,320.3	4.32	115	18,236	5,681		46	21,324	267	45,669
Maine	576.1	6.26		257	4,954	0	0	33		5,224
Maryland	1,703.9	4.15		4,062	1,753		9	295		6,119
Massachusetts	1,591.1	8.41	838	3,662	3,394		72		193	8,519
Michigan	3,817.5	5.08	940	10,543	5,960		1,958	1,453	3,659	24,513
Minnesota	1,878.7	4.26		1,888	6,087		390	2,872	209	11,446
Mississippi	1,094.4	4.41	546	2,532	5,357	0	48		159	8,642
Missouri	1,581.3	4.44	1,070	7,619	3,656	142	373		691	13,551
Montana	429.7	3.30		184	1,112	0	0	1,111	0	2,407
Nebraska	566.8	3.68		922	406	0	33			1,361
Nevada	563.4	4.90		232	166	0		0	0	398
New Hampshire	372.4	9.16	385	274	1,194	0	138	23	27	2,041
New Jersey	2,869.7	8.15	1,004	24,256	3,726	596	296	5,590	806	36,274
New Mexico	532.5	4.35		150	299		14	931	0	1,394
New York	3,703.5	5.62	3,371	11,723	6,262	421	284		1,284	23,345
North Carolina	2,781.2	4.79	1,501	14,903	8,077	601	108	252	214	25,656
North Dakota	510.3	4.44	0		73	0	0		0	73
Ohio	5,722.8	4.21	1,857	15,698	7,805	1,090	2,688	5,062	10,428	44,628
Oklahoma	1,254.4	3.78	154	1,221	1,551	332	141	3,876	381	7,656
Oregon	962.9	3.41	721	710	12,237	74	465	213	369	14,789
Pennsylvania	5,132.6	5.93	2,357	14,441	10,342	1,228	1,172	8,990	9,533	48,063
Rhode Island	417.8	8.51	567	501	284		29	0	145	1,526
South Carolina	1,831.3	3.89	655	10,037	5,609		129		693	17,123
South Dakota	253.3	4.45		51	340	0	0	0	0	391
Tennessee	3,014.6	4.52	2,019	9,533	5,451		595	1,065	691	19,354
Texas	15,452.4	4.03	4,454	47,523	7,848	478	757	39,575	1,902	102,537
Utah	552.6	3.70	103	674	715	0	86	1,474		3,052
Vermont	159.3	7.58	103	94	742		0	0	0	939
Virginia	1,547.7	3.99	501	7,454	5,653		452		215	14,275
Washington	1,386.4	2.85	2,572	2,666	10,456		188	4,247	197	20,326
West Virginia	1,234.3	3.91	782	5,154	767	330	52	306	1,527	6,918
Wisconsin	1,789.2	3.66	318	3,282	14,155		1,883	276	415	20,329
Wyoming	623.5	3.45	0	646	142	0		952	0	1,740
Total	103,616.9		44,274	305,115	212,813	7,643	18,198	139,659	55,937	779,702

Table 14. DOE/OIT Data Ranked by Energy Expenditures

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Fraction of National Total (%)	Cumulative %
1	Texas	15,452.4	14.91	14.91
1	California	7,094.7	6.85	21.76
1	Ohio	5,722.8	5.52	27.28
1	Louisiana	5,320.3	5.13	32.42
1	Pennsylvania	5,132.6	4.95	37.37
1	Illinois	4,942.6	4.77	42.14
1	Michigan	3,817.5	3.68	45.83
1	New York	3,703.5	3.57	49.40
1	Indiana	3,627.2	3.50	52.90
1	Tennessee	3,014.6	2.91	55.81
	New Jersey	2,869.7	2.77	58.58
	North Carolina	2,781.2	2.68	61.26
	Georgia	2,644.5	2.55	63.82
	Alabama	2,394.9	2.31	66.13
	Kentucky	2,105.8	2.03	68.16
	Florida	1,929.1	1.86	70.02
	Minnesota	1,878.7	1.81	71.83
	South Carolina	1,831.3	1.77	73.60
	Wisconsin	1,789.2	1.73	75.33
	Maryland	1,703.9	1.64	76.97
	Massachusetts	1,591.1	1.54	78.51
	Missouri	1,581.3	1.53	80.03
	Virginia	1,547.7	1.49	81.53
	Washington	1,386.4	1.34	82.87
	Kansas	1,351.4	1.30	84.17
	Iowa	1,331.1	1.28	85.45
	Oklahoma	1,254.4	1.21	86.67
	West Virginia	1,234.3	1.19	87.86
	Arkansas	1,178.2	1.14	88.99
	Mississippi	1,094.4	1.06	90.05
	Oregon	962.9	0.93	90.98
	Arizona	928.4	0.90	91.88
	Connecticut	815.3	0.79	92.66
	Colorado	721.9	0.70	93.36
	Wyoming	623.5	0.60	93.96
	Maine	576.1	0.56	94.52
	Nebraska	566.8	0.55	95.06
	Nevada	563.4	0.54	95.61
	Utah	552.6	0.53	96.14
	New Mexico	532.5	0.51	96.65
	North Dakota	510.3	0.49	97.15
	Idaho	455.9	0.44	97.59
	Montana	429.7	0.41	98.00
	Rhode Island	417.8	0.40	98.40
	Hawaii	387.0	0.37	98.78
	New Hampshire	372.4	0.36	99.14
	Delaware	305.9	0.30	99.43
	South Dakota	253.3	0.24	99.68
	Alaska	175.1	0.17	99.85
	Vermont	159.3	0.15	100.00
10	TOTAL	103,616.9	100.00	
	Selected States	57,828.2	55.81	

Table 15. 1996 OIT Data Ranked by Electricity Rates

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)
	Hawaii	387.0	10.03
	New Hampshire	372.4	9.16
	Rhode Island	417.8	8.51
	Alaska	175.1	8.47
	Massachusetts	1,591.1	8.41
	New Jersey	2,869.7	8.15
	Connecticut	815.3	7.86
	Vermont	159.3	7.58
1	California	7,094.7	6.97
	Maine	576.1	6.26
1	Pennsylvania	5,132.6	5.93
1	New York	3,703.5	5.62
1	Illinois	4,942.6	5.24
	Arizona	928.4	5.19
	Florida	1,929.1	5.11
1	Michigan	3,817.5	5.08
	Nevada	563.4	4.90
	North Carolina	2,781.2	4.79
	Kansas	1,351.4	4.70
	Delaware	305.9	4.68
1	Tennessee	3,014.6	4.52
	Arkansas	1,178.2	4.47
	South Dakota	253.3	4.45
	Missouri	1,581.3	4.44
	North Dakota	510.3	4.44
	Mississippi	1,094.4	4.41
	Colorado	721.9	4.35
	New Mexico	532.5	4.35
1	Louisiana	5,320.3	4.32
	Georgia	2,644.5	4.29
	Minnesota	1,878.7	4.26
1	Ohio	5,722.8	4.21
	Maryland	1,703.9	4.15
1	Texas	15,452.4	4.03
	Virginia	1,547.7	3.99
1	Indiana	3,627.2	3.93
	Alabama	2,394.9	3.91
	Iowa	1,331.1	3.91
	West Virginia	1,234.3	3.91
	South Carolina	1,831.3	3.89
	Oklahoma	1,254.4	3.78
	Utah	552.6	3.70
	Nebraska	566.8	3.68
	Wisconsin	1,789.2	3.66
	Wyoming	623.5	3.45
	Oregon	962.9	3.41
	Montana	429.7	3.30
	Kentucky	2,105.8	2.92
	Washington	1,386.4	2.85
	Idaho	455.9	2.68
		0.0	
	TOTAL	103,616.9	
10	Selected States	57,828.2	

Table 16. 1996 OIT Data Ranked by Aluminum Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Aluminum Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	Texas	15,452.4	4.03	4,454	10.1	10.1
1	Indiana	3,627.2	3.93	3,612	8.2	18.2
1	New York	3,703.5	5.62	3,371	7.6	25.8
	Washington	1,386.4	2.85	2,572	5.8	31.6
	Arizona	928.4	5.19	2,533	5.7	37.4
1	Pennsylvania	5,132.6	5.93	2,357	5.3	42.7
1	Illinois	4,942.6	5.24	2,302	5.2	47.9
1	Tennessee	3,014.6	4.52	2,019	4.6	52.4
	Georgia	2,644.5	4.29	2,006	4.5	57.0
1	Ohio	5,722.8	4.21	1,857	4.2	61.2
	Alabama	2,394.9	3.91	1,719	3.9	65.1
	Kentucky	2,105.8	2.92	1,627	3.7	68.7
	North Carolina	2,781.2	4.79	1,501	3.4	72.1
1	California	7,094.7	6.97	1,302	2.9	75.1
	Missouri	1,581.3	4.44	1,070	2.4	77.5
	Connecticut	815.3	7.86	1,007	2.3	79.8
	New Jersey	2,869.7	8.15	1,004	2.3	82.0
	Arkansas	1,178.2	4.47	994	2.2	84.3
1	Michigan	3,817.5	5.08	940	2.1	86.4
	Massachusetts	1,591.1	8.41	838	1.9	88.3
	West Virginia	1,234.3	3.91	782	1.8	90.0
	Oregon	962.9	3.41	721	1.6	91.7
	South Carolina	1,831.3	3.89	655	1.5	93.2
	Rhode Island	417.8	8.51	567	1.3	94.4
	Mississippi	1,094.4	4.41	546	1.2	95.7
	Virginia	1,547.7	3.99	501	1.1	96.8
	New Hampshire	372.4	9.16	385	0.9	97.7
	Wisconsin	1,789.2	3.66	318	0.7	98.4
	Florida	1,929.1	5.11	239	0.5	98.9
	Oklahoma	1,254.4	3.78	154	0.3	99.3
1	Louisiana	5,320.3	4.32	115	0.3	99.5
	Utah	552.6	3.70	103	0.2	99.8
	Vermont	159.3	7.58	103	0.2	100.0
	Alaska	175.1	8.47	0	0.0	100.0
	Hawaii	387.0	10.03	0	0.0	100.0
	Idaho	455.9	2.68	0	0.0	100.0
	North Dakota	510.3	4.44	0	0.0	100.0
	Wyoming	623.5	3.45	0	0.0	100.0
	Colorado	721.9	4.35	0	0.0	100.0
	Delaware	305.9	4.68	0	0.0	100.0
	Iowa	1,331.1	3.91	0	0.0	100.0
	Kansas	1,351.4	4.70	0	0.0	100.0
	Maine	576.1	6.26	0	0.0	100.0
	Maryland	1,703.9	4.15	0	0.0	100.0
	Minnesota	1,878.7	4.26	0	0.0	100.0
	Montana	429.7	3.30	0	0.0	100.0
	Nebraska	566.8	3.68	0	0.0	100.0
	Nevada	563.4	4.90	0	0.0	100.0
	New Mexico	532.5	4.35	0	0.0	100.0
	South Dakota	253.3	4.45	0	0.0	100.0
	TOTAL	103,616.9		44,274	100.0	
10	Selected States	57,828.2		22,329	50.4	

Table 17. 1996 OIT Data Ranked by Chemicals Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Chemicals Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	Texas	15,452.4	4.03	47,523	15.6	15.6
	New Jersey	2,869.7	8.15	24,256	7.9	23.5
1	Louisiana	5,320.3	4.32	18,236	6.0	29.5
1	Illinois	4,942.6	5.24	17,133	5.6	35.1
1	California	7,094.7	6.97	16,417	5.4	40.5
1	Ohio	5,722.8	4.21	15,698	5.1	45.6
	North Carolina	2,781.2	4.79	14,903	4.9	50.5
1	Pennsylvania	5,132.6	5.93	14,441	4.7	55.3
1	New York	3,703.5	5.62	11,723	3.8	59.1
1	Michigan	3,817.5	5.08	10,543	3.5	62.6
	South Carolina	1,831.3	3.89	10,037	3.3	65.8
1	Indiana	3,627.2	3.93	10,023	3.3	69.1
1	Tennessee	3,014.6	4.52	9,533	3.1	72.3
	Missouri	1,581.3	4.44	7,619	2.5	74.8
	Virginia	1,547.7	3.99	7,454	2.4	77.2
	Georgia	2,644.5	4.29	6,752	2.2	79.4
	Florida	1,929.1	5.11	6,668	2.2	81.6
	Kentucky	2,105.8	2.92	5,463	1.8	83.4
	West Virginia	1,234.3	3.91	5,154	1.7	85.1
	Alabama	2,394.9	3.91	4,910	1.6	86.7
	Maryland	1,703.9	4.15	4,062	1.3	88.0
	Connecticut	815.3	7.86	3,858	1.3	89.3
	Massachusetts	1,591.1	8.41	3,662	1.2	90.5
	Iowa	1,331.1	3.91	3,396	1.1	91.6
	Wisconsin	1,789.2	3.66	3,282	1.1	92.7
	Delaware	305.9	4.68	2,803	0.9	93.6
	Washington	1,386.4	2.85	2,666	0.9	94.5
	Mississippi	1,094.4	4.41	2,532	0.8	95.3
	Kansas	1,351.4	4.70	2,083	0.7	96.0
	Minnesota	1,878.7	4.26	1,888	0.6	96.6
	Arkansas	1,178.2	4.47	1,762	0.6	97.2
	Oklahoma	1,254.4	3.78	1,221	0.4	97.6
	Arizona	928.4	5.19	1,069	0.4	97.9
	Idaho	455.9	2.68	978	0.3	98.2
	Nebraska	566.8	3.68	922	0.3	98.5
	Oregon	962.9	3.41	710	0.2	98.8
	Utah	552.6	3.70	674	0.2	99.0
	Wyoming	623.5	3.45	646	0.2	99.2
	Colorado	721.9	4.35	599	0.2	99.4
	Rhode Island	417.8	8.51	501	0.2	99.6
	New Hampshire	372.4	9.16	274	0.1	99.7
	Maine	576.1	6.26	257	0.1	99.7
	Nevada	563.4	4.90	232	0.1	99.8
	Montana	429.7	3.30	184	0.1	99.9
	New Mexico	532.5	4.35	150	0.0	99.9
	Vermont	159.3	7.58	94	0.0	100.0
	Hawaii	387.0	10.03	73	0.0	100.0
	South Dakota	253.3	4.45	51	0.0	100.0
	Alaska	175.1	8.47	0	0.0	100.0
	North Dakota	510.3	4.44	0	0.0	100.0
	TOTAL	103,616.9		305,115	100.0	
10	Selected States	57,828.2		171,270	56.1	

Table 18. 1996 OIT Data Ranked by Forest Products Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Forest Products Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	California	7,094.7	6.97	14,381	6.8	6.8
	Wisconsin	1,789.2	3.66	14,155	6.7	13.4
	Oregon	962.9	3.41	12,237	5.8	19.2
	Georgia	2,644.5	4.29	11,988	5.6	24.8
	Washington	1,386.4	2.85	10,456	4.9	29.7
1	Pennsylvania	5,132.6	5.93	10,342	4.9	34.6
	Alabama	2,394.9	3.91	9,533	4.5	39.0
	North Carolina	2,781.2	4.79	8,077	3.8	42.8
1	Texas	15,452.4	4.03	7,848	3.7	46.5
1	Ohio	5,722.8	4.21	7,805	3.7	50.2
1	Illinois	4,942.6	5.24	6,632	3.1	53.3
1	New York	3,703.5	5.62	6,262	2.9	56.3
	Minnesota	1,878.7	4.26	6,087	2.9	59.1
1	Michigan	3,817.5	5.08	5,960	2.8	61.9
	Arkansas	1,178.2	4.47	5,859	2.8	64.7
1	Louisiana	5,320.3	4.32	5,681	2.7	67.3
	Virginia	1,547.7	3.99	5,653	2.7	70.0
	South Carolina	1,831.3	3.89	5,609	2.6	72.6
1	Tennessee	3,014.6	4.52	5,451	2.6	75.2
	Florida	1,929.1	5.11	5,442	2.6	77.7
	Mississippi	1,094.4	4.41	5,357	2.5	80.3
	Maine	576.1	6.26	4,954	2.3	82.6
1	Indiana	3,627.2	3.93	4,847	2.3	84.9
	New Jersey	2,869.7	8.15	3,726	1.8	86.6
	Missouri	1,581.3	4.44	3,656	1.7	88.3
	Massachusetts	1,591.1	8.41	3,394	1.6	89.9
	Kentucky	2,105.8	2.92	2,701	1.3	91.2
	Idaho	455.9	2.68	1,999	0.9	92.1
	Maryland	1,703.9	4.15	1,753	0.8	93.0
	Connecticut	815.3	7.86	1,656	0.8	93.7
	Oklahoma	1,254.4	3.78	1,551	0.7	94.5
	Iowa	1,331.1	3.91	1,244	0.6	95.1
	Arizona	928.4	5.19	1,199	0.6	95.6
	New Hampshire	372.4	9.16	1,194	0.6	96.2
	Kansas	1,351.4	4.70	1,150	0.5	96.7
	Montana	429.7	3.30	1,112	0.5	97.2
	Colorado	721.9	4.35	796	0.4	97.6
	West Virginia	1,234.3	3.91	767	0.4	98.0
	Vermont	159.3	7.58	742	0.3	98.3
	Utah	552.6	3.70	715	0.3	98.7
	Delaware	305.9	4.68	588	0.3	98.9
	Alaska	175.1	8.47	504	0.2	99.2
	Nebraska	566.8	3.68	406	0.2	99.4
	South Dakota	253.3	4.45	340	0.2	99.5
	New Mexico	532.5	4.35	299	0.1	99.7
	Rhode Island	417.8	8.51	284	0.1	99.8
	Nevada	563.4	4.90	166	0.1	99.9
	Wyoming	623.5	3.45	142	0.1	99.9
	North Dakota	510.3	4.44	73	0.0	100.0
	Hawaii	387.0	10.03	40	0.0	100.0
	TOTAL	103,616.9		212,813	100.0	
10	Selected States	57,828.2		75,209	35.3	

Table 19. 1996 OIT Data Ranked by Glass Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Glass Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	Pennsylvania	5,132.6	5.93	1,228	16.1	16.1
1	California	7,094.7	6.97	1,212	15.9	31.9
1	Ohio	5,722.8	4.21	1,090	14.3	46.2
	North Carolina	2,781.2	4.79	601	7.9	54.0
	New Jersey	2,869.7	8.15	596	7.8	61.8
1	Texas	15,452.4	4.03	478	6.3	68.1
1	New York	3,703.5	5.62	421	5.5	73.6
1	Illinois	4,942.6	5.24	389	5.1	78.7
1	Indiana	3,627.2	3.93	371	4.9	83.6
	Oklahoma	1,254.4	3.78	332	4.3	87.9
	West Virginia	1,234.3	3.91	330	4.3	92.2
	Kentucky	2,105.8	2.92	213	2.8	95.0
	Florida	1,929.1	5.11	166	2.2	97.2
	Missouri	1,581.3	4.44	142	1.9	99.0
	Oregon	962.9	3.41	74	1.0	100.0
	Alabama	2,394.9	3.91	0	0.0	100.0
	Alaska	175.1	8.47	0	0.0	100.0
	Arizona	928.4	5.19	0	0.0	100.0
	Delaware	305.9	4.68	0	0.0	100.0
	Hawaii	387.0	10.03	0	0.0	100.0
	Idaho	455.9	2.68	0	0.0	100.0
	Iowa	1,331.1	3.91	0	0.0	100.0
	Maine	576.1	6.26	0	0.0	100.0
	Mississippi	1,094.4	4.41	0	0.0	100.0
	Montana	429.7	3.30	0	0.0	100.0
	Nebraska	566.8	3.68	0	0.0	100.0
	Nevada	563.4	4.90	0	0.0	100.0
	New Hampshire	372.4	9.16	0	0.0	100.0
	North Dakota	510.3	4.44	0	0.0	100.0
	South Dakota	253.3	4.45	0	0.0	100.0
	Utah	552.6	3.70	0	0.0	100.0
	Wyoming	623.5	3.45	0	0.0	100.0
	Arkansas	1,178.2	4.47	0	0.0	100.0
	Colorado	721.9	4.35	0	0.0	100.0
	Connecticut	815.3	7.86	0	0.0	100.0
	Georgia	2,644.5	4.29	0	0.0	100.0
	Kansas	1,351.4	4.70	0	0.0	100.0
1	Louisiana	5,320.3	4.32	0	0.0	100.0
	Maryland	1,703.9	4.15	0	0.0	100.0
	Massachusetts	1,591.1	8.41	0	0.0	100.0
1	Michigan	3,817.5	5.08	0	0.0	100.0
	Minnesota	1,878.7	4.26	0	0.0	100.0
	New Mexico	532.5	4.35	0	0.0	100.0
	Rhode Island	417.8	8.51	0	0.0	100.0
	South Carolina	1,831.3	3.89	0	0.0	100.0
1	Tennessee	3,014.6	4.52	0	0.0	100.0
	Vermont	159.3	7.58	0	0.0	100.0
	Virginia	1,547.7	3.99	0	0.0	100.0
	Washington	1,386.4	2.85	0	0.0	100.0
	Wisconsin	1,789.2	3.66	0	0.0	100.0
	TOTAL	103,616.9		7,643	100.0	
10	Selected States	57,828.2		5,189	67.9	

Table 20. 1996 OIT Data Ranked by Metal Casting Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Metal Casting Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	Ohio	5,722.8	4.21	2,688	14.8	14.8
1	Michigan	3,817.5	5.08	1,958	10.8	25.5
	Wisconsin	1,789.2	3.66	1,883	10.3	35.9
1	Indiana	3,627.2	3.93	1,499	8.2	44.1
1	Pennsylvania	5,132.6	5.93	1,172	6.4	50.6
1	Illinois	4,942.6	5.24	1,128	6.2	56.8
	Alabama	2,394.9	3.91	1,083	6.0	62.7
1	California	7,094.7	6.97	903	5.0	67.7
1	Texas	15,452.4	4.03	757	4.2	71.8
1	Tennessee	3,014.6	4.52	595	3.3	75.1
	Oregon	962.9	3.41	465	2.6	77.7
	Virginia	1,547.7	3.99	452	2.5	80.1
	Minnesota	1,878.7	4.26	390	2.1	82.3
	Missouri	1,581.3	4.44	373	2.0	84.3
	Iowa	1,331.1	3.91	321	1.8	86.1
	New Jersey	2,869.7	8.15	296	1.6	87.7
1	New York	3,703.5	5.62	284	1.6	89.3
	Georgia	2,644.5	4.29	222	1.2	90.5
	Kentucky	2,105.8	2.92	214	1.2	91.7
	Washington	1,386.4	2.85	188	1.0	92.7
	Arkansas	1,178.2	4.47	163	0.9	93.6
	Oklahoma	1,254.4	3.78	141	0.8	94.4
	New Hampshire	372.4	9.16	138	0.8	95.1
	South Carolina	1,831.3	3.89	129	0.7	95.8
	Kansas	1,351.4	4.70	123	0.7	96.5
	North Carolina	2,781.2	4.79	108	0.6	97.1
	Utah	552.6	3.70	86	0.5	97.6
	Massachusetts	1,591.1	8.41	72	0.4	98.0
	Florida	1,929.1	5.11	71	0.4	98.4
	West Virginia	1,234.3	3.91	52	0.3	98.7
	Mississippi	1,094.4	4.41	48	0.3	98.9
1	Louisiana	5,320.3	4.32	46	0.3	99.2
	Nebraska	566.8	3.68	33	0.2	99.4
	Rhode Island	417.8	8.51	29	0.2	99.5
	Arizona	928.4	5.19	28	0.2	99.7
	Connecticut	815.3	7.86	26	0.1	99.8
	New Mexico	532.5	4.35	14	0.1	99.9
	Colorado	721.9	4.35	11	0.1	100.0
	Maryland	1,703.9	4.15	9	0.0	100.0
	Alaska	175.1	8.47	0	0.0	100.0
	Delaware	305.9	4.68	0	0.0	100.0
	Hawaii	387.0	10.03	0	0.0	100.0
	Idaho	455.9	2.68	0	0.0	100.0
	Maine	576.1	6.26	0	0.0	100.0
	Montana	429.7	3.30	0	0.0	100.0
	North Dakota	510.3	4.44	0	0.0	100.0
	South Dakota	253.3	4.45	0	0.0	100.0
	Vermont	159.3	7.58	0	0.0	100.0
	Nevada	563.4	4.90	0	0.0	100.0
	Wyoming	623.5	3.45	0	0.0	100.0
	TOTAL	103,616.9		18,198	100.0	
10	Selected States	57,828.2		11,030	60.6	

Table 21. 1996 OIT Data Ranked by Petroleum Refining Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Petroleum Refining Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	Texas	15,452.4	4.03	39,575	28.3	28.3
1	Louisiana	5,320.3	4.32	21,324	15.3	43.6
1	California	7,094.7	6.97	18,775	13.4	57.0
1	Illinois	4,942.6	5.24	9,241	6.6	63.7
1	Pennsylvania	5,132.6	5.93	8,990	6.4	70.1
	New Jersey	2,869.7	8.15	5,590	4.0	74.1
1	Ohio	5,722.8	4.21	5,062	3.6	77.7
	Washington	1,386.4	2.85	4,247	3.0	80.8
1	Indiana	3,627.2	3.93	4,234	3.0	83.8
	Oklahoma	1,254.4	3.78	3,876	2.8	86.6
	Kansas	1,351.4	4.70	3,111	2.2	88.8
	Minnesota	1,878.7	4.26	2,872	2.1	90.9
	Utah	552.6	3.70	1,474	1.1	91.9
1	Michigan	3,817.5	5.08	1,453	1.0	93.0
	Alabama	2,394.9	3.91	1,223	0.9	93.8
	Montana	429.7	3.30	1,111	0.8	94.6
1	Tennessee	3,014.6	4.52	1,065	0.8	95.4
	Alaska	175.1	8.47	1,045	0.7	96.1
	Wyoming	623.5	3.45	952	0.7	96.8
	New Mexico	532.5	4.35	931	0.7	97.5
	Colorado	721.9	4.35	754	0.5	98.0
	Arkansas	1,178.2	4.47	744	0.5	98.6
	Florida	1,929.1	5.11	310	0.2	98.8
	West Virginia	1,234.3	3.91	306	0.2	99.0
	Maryland	1,703.9	4.15	295	0.2	99.2
	Wisconsin	1,789.2	3.66	276	0.2	99.4
	North Carolina	2,781.2	4.79	252	0.2	99.6
	Oregon	962.9	3.41	213	0.2	99.7
	Connecticut	815.3	7.86	172	0.1	99.9
	Iowa	1,331.1	3.91	71	0.1	99.9
	Arizona	928.4	5.19	59	0.0	100.0
	Maine	576.1	6.26	33	0.0	100.0
	New Hampshire	372.4	9.16	23	0.0	100.0
	Idaho	455.9	2.68	0	0.0	100.0
	Nevada	563.4	4.90	0	0.0	100.0
	Rhode Island	417.8	8.51	0	0.0	100.0
	South Dakota	253.3	4.45	0	0.0	100.0
	Vermont	159.3	7.58	0	0.0	100.0
	Delaware	305.9	4.68	0	0.0	100.0
	Georgia	2,644.5	4.29	0	0.0	100.0
	Hawaii	387.0	10.03	0	0.0	100.0
	Kentucky	2,105.8	2.92	0	0.0	100.0
	Massachusetts	1,591.1	8.41	0	0.0	100.0
	Mississippi	1,094.4	4.41	0	0.0	100.0
	Missouri	1,581.3	4.44	0	0.0	100.0
	Nebraska	566.8	3.68	0	0.0	100.0
1	New York	3,703.5	5.62	0	0.0	100.0
	North Dakota	510.3	4.44	0	0.0	100.0
	South Carolina	1,831.3	3.89	0	0.0	100.0
	Virginia	1,547.7	3.99	0	0.0	100.0
	TOTAL	103,616.9		139,659	100.0	
10	Selected States	57,828.2		109,719	78.6	

Table 22. 1996 OIT Data Ranked by Steel Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Steel Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	Ohio	5,722.8	4.21	10,428	18.6	18.6
1	Pennsylvania	5,132.6	5.93	9,533	17.0	35.7
1	Indiana	3,627.2	3.93	9,163	16.4	52.1
1	Illinois	4,942.6	5.24	4,641	8.3	60.4
1	Michigan	3,817.5	5.08	3,659	6.5	66.9
1	California	7,094.7	6.97	2,158	3.9	70.8
	Alabama	2,394.9	3.91	1,962	3.5	74.3
1	Texas	15,452.4	4.03	1,902	3.4	77.7
	West Virginia	1,234.3	3.91	1,527	2.7	80.4
	Kentucky	2,105.8	2.92	1,327	2.4	82.8
1	New York	3,703.5	5.62	1,284	2.3	85.1
	Arkansas	1,178.2	4.47	818	1.5	86.5
	New Jersey	2,869.7	8.15	806	1.4	88.0
	South Carolina	1,831.3	3.89	693	1.2	89.2
	Missouri	1,581.3	4.44	691	1.2	90.4
1	Tennessee	3,014.6	4.52	691	1.2	91.7
	Georgia	2,644.5	4.29	477	0.9	92.5
	Connecticut	815.3	7.86	459	0.8	93.4
	Wisconsin	1,789.2	3.66	415	0.7	94.1
	Florida	1,929.1	5.11	386	0.7	94.8
	Oklahoma	1,254.4	3.78	381	0.7	95.5
	Oregon	962.9	3.41	369	0.7	96.1
	Colorado	721.9	4.35	279	0.5	96.6
1	Louisiana	5,320.3	4.32	267	0.5	97.1
	Virginia	1,547.7	3.99	215	0.4	97.5
	North Carolina	2,781.2	4.79	214	0.4	97.9
	Minnesota	1,878.7	4.26	209	0.4	98.2
	Washington	1,386.4	2.85	197	0.4	98.6
	Massachusetts	1,591.1	8.41	193	0.3	98.9
	Mississippi	1,094.4	4.41	159	0.3	99.2
	Rhode Island	417.8	8.51	145	0.3	99.5
	Iowa	1,331.1	3.91	142	0.3	99.7
	Delaware	305.9	4.68	120	0.2	100.0
	New Hampshire	372.4	9.16	27	0.0	100.0
	Alaska	175.1	8.47	0	0.0	100.0
	Hawaii	387.0	10.03	0	0.0	100.0
	Idaho	455.9	2.68	0	0.0	100.0
	Kansas	1,351.4	4.70	0	0.0	100.0
	Montana	429.7	3.30	0	0.0	100.0
	Nevada	563.4	4.90	0	0.0	100.0
	New Mexico	532.5	4.35	0	0.0	100.0
	North Dakota	510.3	4.44	0	0.0	100.0
	South Dakota	253.3	4.45	0	0.0	100.0
	Vermont	159.3	7.58	0	0.0	100.0
	Wyoming	623.5	3.45	0	0.0	100.0
	Arizona	928.4	5.19	0	0.0	100.0
	Maine	576.1	6.26	0	0.0	100.0
	Maryland	1,703.9	4.15	0	0.0	100.0
	Nebraska	566.8	3.68	0	0.0	100.0
	Utah	552.6	3.70	0	0.0	100.0
	TOTAL	103,616.9		55,937	100.0	
10	Selected States	57,828.2		43,726	78.2	

Table 23. 1996 OIT Data Ranked by Total Industrial Sales

Selected for Sample? (Yes = 1)	State	Energy Expenditures ($Millions)	Energy Cost (¢/kWh)	Total Industrial Sales ($Millions)	Fraction of National Total (%)	Cumulative Fraction (%)
1	Texas	15,452.4	4.03	102,537	13.2	13.2
1	California	7,094.7	6.97	55,148	7.1	20.2
1	Pennsylvania	5,132.6	5.93	48,063	6.2	26.4
1	Louisiana	5,320.3	4.32	45,669	5.9	32.2
1	Ohio	5,722.8	4.21	44,628	5.7	38.0
1	Illinois	4,942.6	5.24	41,466	5.3	43.3
	New Jersey	2,869.7	8.15	36,274	4.7	47.9
1	Indiana	3,627.2	3.93	33,749	4.3	52.3
	North Carolina	2,781.2	4.79	25,656	3.3	55.6
1	Michigan	3,817.5	5.08	24,513	3.1	58.7
1	New York	3,703.5	5.62	23,345	3.0	61.7
	Alabama	2,394.9	3.91	20,430	2.6	64.3
	Wisconsin	1,789.2	3.66	20,329	2.6	66.9
	Washington	1,386.4	2.85	20,326	2.6	69.5
1	Tennessee	3,014.6	4.52	19,354	2.5	72.0
	Georgia	2,644.5	4.29	19,168	2.5	74.5
	South Carolina	1,831.3	3.89	17,123	2.2	76.7
	Oregon	962.9	3.41	14,789	1.9	78.6
	Virginia	1,547.7	3.99	14,275	1.8	80.4
	Missouri	1,581.3	4.44	13,551	1.7	82.1
	Florida	1,929.1	5.11	13,282	1.7	83.8
	Kentucky	2,105.8	2.92	11,545	1.5	85.3
	Minnesota	1,878.7	4.26	11,446	1.5	86.8
	Arkansas	1,178.2	4.47	10,340	1.3	88.1
	Mississippi	1,094.4	4.41	8,642	1.1	89.2
	Massachusetts	1,591.1	8.41	8,519	1.1	90.3
	Oklahoma	1,254.4	3.78	7,656	1.0	91.3
	Connecticut	815.3	7.86	7,178	0.9	92.2
	West Virginia	1,234.3	3.91	6,918	0.9	93.1
	Kansas	1,351.4	4.70	6,467	0.8	93.9
	Maryland	1,703.9	4.15	6,119	0.8	94.7
	Maine	576.1	6.26	5,224	0.7	95.4
	Iowa	1,331.1	3.91	5,174	0.7	96.0
	Arizona	928.4	5.19	4,888	0.6	96.7
	Delaware	305.9	4.68	3,511	0.5	97.1
	Utah	552.6	3.70	3,052	0.4	97.5
	Idaho	455.9	2.68	2,977	0.4	97.9
	Colorado	721.9	4.35	2,439	0.3	98.2
	Montana	429.7	3.30	2,407	0.3	98.5
	New Hampshire	372.4	9.16	2,041	0.3	98.8
	Wyoming	623.5	3.45	1,740	0.2	99.0
	Alaska	175.1	8.47	1,549	0.2	99.2
	Rhode Island	417.8	8.51	1,526	0.2	99.4
	New Mexico	532.5	4.35	1,394	0.2	99.6
	Nebraska	566.8	3.68	1,361	0.2	99.8
	Vermont	159.3	7.58	939	0.1	99.9
	Nevada	563.4	4.90	398	0.1	99.9
	South Dakota	253.3	4.45	391	0.1	100.0
	Hawaii	387.0	10.03	113	0.0	100.0
	North Dakota	510.3	4.44	73	0.0	100.0
	TOTAL	103,616.9		779,702	100.0	
10	Selected States	57,828.2		438,472	56.2	

distributed generator is "dispatched." If not, electricity is purchased from the grid. Thus, dispatch is based on the difference between the *incremental* cost for electricity from the distributed generator and the cost to purchase electricity from the grid. DUVal-C then makes an inventory of the emissions that would occur given the distributed generator's economic dispatch.

Once the annual economic dispatch is determined, the total benefit/cost ratio for the distributed generator option is calculated. DUVal-C adds the capital equipment-related cost to the incremental/variable cost incurred for distributed generator operation during the annual hours of economic dispatch.

Finally, the customer's total cost to own and operate the distributed generator is compared to the avoided cost associated with not having to purchase equivalent electricity from the grid. The result is the total benefit to cost (B/C) ratio. If the avoided bill (benefit) is greater than the total cost to own and operate the distributed generator (cost), then the benefit/cost ratio exceeds 1 and the distributed generator installation under consideration is economically competitive.

If a distributed generator is cost-effective (i.e., the benefit cost ratio exceeds 1), then in theory it is cost-effective for all load in the region of the state for which the price (tariff) applies (the respective utility's service area). For example, if a microturbine has an overall B/C ratio greater than 1, then assuming that all customers in the large industrial and institutional classes in the same utility service area use the same amount of electricity at the same times, microturbines are cost effective for all such customers in the region for which the tariff price applies.

Emissions from Cost-Effective Operation of Distributed Generation

After determining the economic hours of operation and the overall benefit/cost relationship for each distributed generator, DUVal-C inventories total emissions, both for the central-generation-only situation (no distributed generation), and for the economically optimal mix of cost-effective distributed generation and central generation (i.e., power and electricity are purchased from the grid when doing so is less expensive). Results are stated as the change in per cent, relative to the central-station-only scenario, for each respective state.

Customer Model Results

Description of Results and Result Tables

Results are presented for evaluation of distributed generator competitiveness versus the grid, for each of six distributed generators evaluated. Each distributed generator table includes the key state-specific criteria, such as industrial energy sales, provided for context. These tables also include state-specific calculations for distributed generators in the ten states evaluated. At the bottom of each table the extrapolated and total national results are shown.

Within each distributed generator-specific results table, the three recurring state-by-state input values shown are:

1) industrial electric energy sales projected for 2002,
2) the portion of all U.S. industrial sales that occur in the respective state, and
3) the estimated peak electric demand from all in-state industrial loads.

Industrial electric energy sales projected for 2002 are the projected sales of electric energy (Millions of kWh) to the industrial sector, for the ten states evaluated. It is based on EIA sales data for 1999 [14] and an assumed growth in energy use of 2% per year. Also shown are state-by-state values, the sum of all states' sales (which represents the electric energy sales for the ten states evaluated for the active industrial sector), and finally, the column includes total U.S. sales to the industrial sector.

Each state's portion of national industrial electric energy sales is calculated as the ratio of the respective state's energy sales (as described above) to the total for the entire U.S. (in the previous column). The sum of these ten values is shown; it indicates the percentage of national industrial electric energy sales that are made within the ten states evaluated.

As discussed previously, industrial loads are assumed to have a 0.8 average annual electric load factor. To estimate the load for each state and for the U.S. involves dividing the region's energy use (in units of GWh) by (8,760*0.8) hours/year to calculate estimated load.

To the right of those data, corresponding results from DUVal-C are listed. These include:

1) Calculated optimal annual operation hours, total cost basis
2) Estimated GW of installed DG capacity (nameplate)
3) Net change in air emissions due to DG adoption.

In the next column in the result tables, the estimated distributed generator nameplate capacity (aggregated power rating) indicated by the DUVal-C results is shown. If a distributed generator is determined to be economic for operation during the year in a given state, its full capacity is indicated in the column labeled Estimated GW of DG Installed Capacity. Therefore, it is very important to note that installing a distributed generator that only operates for a few hours per year may indeed be economically sound for customers, but may or may not obviate the need for the same amount of central generation capacity upstream to serve the balance of load hours.

Table 24. Customer Model Results – Microturbine

State	Industrial Electric Energy Sales (GWh, 2002)	Portion of Total US Industrial Electric Energy Sales	Approx-imate** Industrial Annual Average Electric Load (GW)	Calculated Optimal DG Annual Operation Hours, Total Cost Basis	Fraction of Annual Load Hours Served by DG	Estimated Economic DG Capacity (GW)	Net Change in Air Emissions Due to DG Adoption					
							NOx	SOx	CO2	CO	PM	VOC
CA	64,378	6.1%	10.3	0	0.0%	0.0						
IL	46,310	4.4%	7.4	0	0.0%	0.0						
IN	50,055	4.7%	8.0	0	0.0%	0.0						
LA	33,458	3.1%	5.4	0	0.0%	0.0						
MI	38,918	3.7%	6.3	8,640	98.6%	6.3	-65.8%	-98.2%	-9.7%	+916.1%	-46.9%	+39.2%
NY	26,767	2.5%	4.3	1,200	13.7%	4.3	-9.1%	-13.6%	-1.4%	+127.2%	-6.5%	+5.4%
OH	78,796	7.4%	12.7	0	0.0%	0.0						
PA	51,486	4.8%	8.3	0	0.0%	0.0						
TN	46,215	4.3%	7.4	0	0.0%	0.0						
TX	106,487	10.0%	17.1	0	0.0%	0.0						
10-State Values--Industrial Sector	542,870	51.1%	87.2			10.6	-5.2%	-7.7%	-0.8%	+71.9%	-3.7%	+3.1%
					U.S. Economic DG Load (GW)	20.7	Emissions (000 tons)					
U.S. Total and Extrapolated Values--Industrial Sector	1,063,252	100%	170.9			U.S. Total, from Central Gen., Industrial Sector	2,070.8	3,532.3	789,322.4	154.2	113.8	17.1
						Change due to DG Use	-107.1	-272.5	-6032.1	+110.95	-4.2	+0.53
						Net total	1,963.7	3,259.8	783,290.3	265.2	109.6	17.7

** Derived from energy use and assuming an annual load factor of .8

Table 25. Customer Model Results – Advanced Turbine System

State	Industrial Electric Energy Sales (GWh, 2002)	Portion of Total US Industrial Electric Energy Sales	Approx-imate** Industrial Annual Average Electric Load (GW)	Calculated Optimal DG Annual Operation Hours, Total Cost Basis	Fraction of Annual Load Hours Served by DG	Estimated Economic DG Capacity (GW)	Net Change in Air Emissions Due to DG Adoption					
							NOx	SOx	CO2	CO	PM	VOC
CA	64,378	6.1%	10.3	8,629	98.5%	10.3	-88.3%	-98.2%	-27.5%	-5.6%	-58.9%	+4.8%
IL	46,310	4.4%	7.4	1,920	21.9%	7.4	-19.6%	-21.9%	-6.1%	-1.2%	-13.1%	+1.1%
IN	50,055	4.7%	8.0	0	0.0%	0.0						
LA	33,458	3.1%	5.4	0	0.0%	0.0						
MI	38,918	3.7%	6.3	8,629	98.5%	6.3	-88.3%	-98.2%	-27.5%	-5.6%	-58.9%	+4.8%
NY	26,767	2.5%	4.3	8,629	98.5%	4.3	-88.3%	-98.2%	-27.5%	-5.6%	-58.9%	+4.8%
OH	78,796	7.4%	12.7	0	0.0%	0.0						
PA	51,486	4.8%	8.3	8,629	98.5%	8.3	-88.3%	-98.2%	-27.5%	-5.6%	-58.9%	+4.8%
TN	46,215	4.3%	7.4	8,629	98.5%	7.4	-88.3%	-98.2%	-27.5%	-5.6%	-58.9%	+4.8%
TX	106,487	10.0%	17.1	1,200	13.7%	17.1	-12.3%	-13.7%	-3.8%	-0.8%	-8.2%	+0.7%
10-State Values--Industrial Sector	542,870	51.1%	87.2			61.2	-41.1%	-45.8%	-12.8%	-2.6%	-27.4%	+2.2%
					U.S. Economic DG Load (GW)	119.8	Emissions (000 tons)					
U.S. Total and Extrapolated Values--Industrial Sector	1,063,252	100%	170.9			U.S. Total, from Central Gen., Industrial Sector	2,070.8	3,532.3	789,322.4	154.2	113.8	17.1
						Change due to DG Use	-851.5	-1616.1	-101199.5	-4.0	-31.2	+0.38
						Net total	1,219.3	1,916.2	688,122.9	150.2	82.5	17.5

** Derived from energy use and assuming an annual load factor of .8

Table 26. Customer Model Results – Advanced Turbine System with CHP

State	Industrial Electric Energy Sales (GWh, 2002)	Portion of Total US Industrial Electric Energy Sales	Approx-imate** Industrial Annual Average Electric Load (GW)	Calculated Optimal DG Annual Operation Hours, Total Cost Basis	Fraction of Annual Load Hours Served by DG	Estimated Economic DG Capacity (GW)	Net Change in Air Emissions Due to DG Adoption					
							NOx	SOx	CO2	CO	PM	VOC
CA	64,378	6.1%	10.3	8,629	98.5%	10.3	-91.1%	-98.2%	-56.4%	-72.0%	-68.9%	-56.2%
IL	46,310	4.4%	7.4	8,629	98.5%	7.4	-91.1%	-98.2%	-56.4%	-72.0%	-68.9%	-56.2%
IN	50,055	4.7%	8.0	0	0.0%	0.0						
LA	33,458	3.1%	5.4	0	0.0%	0.0						
MI	38,918	3.7%	6.3	8,629	98.5%	6.3	-91.1%	-98.2%	-56.4%	-72.0%	-68.9%	-56.2%
NY	26,767	2.5%	4.3	8,629	98.5%	4.3	-91.1%	-98.2%	-56.4%	-72.0%	-68.9%	-56.2%
OH	78,796	7.4%	12.7	0	0.0%	0.0						
PA	51,486	4.8%	8.3	8,629	98.5%	8.3	-91.1%	-98.2%	-56.4%	-72.0%	-68.9%	-56.2%
TN	46,215	4.3%	7.4	8,629	98.5%	7.4	-91.1%	-98.2%	-56.4%	-72.0%	-68.9%	-56.2%
TX	106,487	10.0%	17.1	0	0.0%	0.0						
10-State Values--Industrial Sector	542,870	51.1%	87.2			44.0	-46.0%	-49.6%	-28.5%	-36.3%	-34.8%	-28.4%
					U.S. Economic DG Load (GW)	86.3	**Emissions (000 tons)**					
U.S. Total and Extrapolated Values--Industrial Sector	1,063,252	100%	170.9			U.S. Total, from Central Gen., Industrial Sector	2,070.8	3,532.3	789,322.4	154.2	113.8	17.1
						Change due to DG Use	-952.2	-1751.6	-224749.6	-56.0	-39.6	-4.9
						Net total	1,118.6	1,780.7	564,572.8	98.2	74.2	12.3

** Derived from energy use and assuming an annual load factor of .8

Table 27. Customer Model Results – Dual Fuel Engine

State	Industrial Electric Energy Sales (GWh, 2002)	Portion of Total US Industrial Electric Energy Sales	Approximate** Industrial Annual Average Electric Load (GW)	Calculated Optimal DG Annual Operation Hours, Total Cost Basis	Fraction of Annual Load Hours Served by DG	Estimated Economic DG Capacity (GW)	Net Change in Air Emissions Due to DG Adoption					
							NOx	SOx	CO2	CO	PM	VOC
CA	64,378	6.1%	10.3	0	0.0%	0.0						
IL	46,310	4.4%	7.4	0	0.0%	0.0						
IN	50,055	4.7%	8.0	0	0.0%	0.0						
LA	33,458	3.1%	5.4	0	0.0%	0.0						
MI	38,918	3.7%	6.3	8,640	98.6%	6.3	+186.5%	-97.3%	-8.9%	+12231.6%	+165.6%	+3003.1%
NY	26,767	2.5%	4.3	1,200	13.7%	4.3	+25.9%	-13.5%	-1.2%	+1698.8%	+23.0%	+417.1%
OH	78,796	7.4%	12.7	0	0.0%	0.0						
PA	51,486	4.8%	8.3	0	0.0%	0.0						
TN	46,215	4.3%	7.4	0	0.0%	0.0						
TX	106,487	10.0%	17.1	0	0.0%	0.0						
10-State Values--Industrial Sector	542,870	51.1%	87.2			10.6	+14.6%	-7.6%	-0.7%	+960.6%	+13.0%	+235.9%
					U.S. Economic DG Load (GW)	20.7	Emissions (000 tons)					
U.S. Total and Extrapolated Values--Industrial Sector	1,063,252	100%	170.9			U.S. Total, from Central Gen., Industrial Sector	2,070.8	3,532.3	789,322.4	154.2	113.8	17.1
						Change due to DG Use	+303.35	-269.9	-5490.9	+1481.36	+14.79	+40.41
						Net total	2,374.2	3,262.4	783,831.5	1,635.6	128.5	57.5

** Derived from energy use and assuming an annual load factor of .8

Table 28. Customer Model Results – Conventional Fuel Cell

State	Industrial Electric Energy Sales (GWh, 2002)	Portion of Total US Industrial Electric Energy Sales	Approx-imate** Industrial Annual Average Electric Load (GW)	Calculated Optimal DG Annual Operation Hours, Total Cost Basis	Fraction of Annual Load Hours Served by DG	Estimated Economic DG Capacity (GW)	Net Change in Air Emissions Due to DG Adoption					
							NOx	SOx	CO2	CO	PM	VOC
CA	64,378	6.1%	10.3	0	0.0%	0.0						
IL	46,310	4.4%	7.4	0	0.0%	0.0						
IN	50,055	4.7%	8.0	0	0.0%	0.0						
LA	33,458	3.1%	5.4	0	0.0%	0.0						
MI	38,918	3.7%	6.3	0	0.0%	0.0						
NY	26,767	2.5%	4.3	0	0.0%	0.0						
OH	78,796	7.4%	12.7	0	0.0%	0.0						
PA	51,486	4.8%	8.3	0	0.0%	0.0						
TN	46,215	4.3%	7.4	0	0.0%	0.0						
TX	106,487	10.0%	17.1	0	0.0%	0.0						
10-State Values--Industrial Sector	542,870	51.1%	87.2			0.0						
				U.S. Economic DG Load (GW)		0.0	Emissions (000 tons)					
U.S. Total and Extrapolated Values--Industrial Sector	1,063,252	100%	170.9			U.S. Total, from Central Gen., Industrial Sector	2,070.8	3,532.3	789,322.4	154.2	113.8	17.1
						Change due to DG Use	0.0	0.0	0.0	0.0	0.0	0.0
						Net total	2,070.8	3,532.3	789,322.4	154.2	113.8	17.1

** Derived from energy use and assuming an annual load factor of .8

Table 29. Customer Model Results – Advanced Fuel Cell

State	Industrial Electric Energy Sales (GWh, 2002)	Portion of Total US Industrial Electric Energy Sales	Approx-imate** Industrial Annual Average Electric Load (GW)	Calculated Optimal DG Annual Operation Hours, Total Cost Basis	Fraction of Annual Load Hours Served by DG	Estimated Economic DG Capacity (GW)	Net Change in Air Emissions Due to DG Adoption: NOx	SOx	CO2	CO	PM	VOC
CA	64,378	6.1%	10.3	0	0.0%	0.0						
IL	46,310	4.4%	7.4	0	0.0%	0.0						
IN	50,055	4.7%	8.0	0	0.0%	0.0						
LA	33,458	3.1%	5.4	0	0.0%	0.0						
MI	38,918	3.7%	6.3	8,585	98.0%	6.3	-97.6%	-98.0%	-27.4%	-98.0%	-98.0%	-98.0%
NY	26,767	2.5%	4.3	0	0.0%	0.0						
OH	78,796	7.4%	12.7	0	0.0%	0.0						
PA	51,486	4.8%	8.3	0	0.0%	0.0						
TN	46,215	4.3%	7.4	0	0.0%	0.0						
TX	106,487	10.0%	17.1	0	0.0%	0.0						
10-State Values--Industrial Sector	542,870	51.1%	87.2			6.3	-7.0%	-7.0%	-2.0%	-7.0%	-7.0%	-7.0%
					U.S. Economic DG Load (GW)	12.2						
U.S. Total and Extrapolated Values--Industrial Sector	1,063,252	100%	170.9									

Emissions (000 tons)	NOx	SOx	CO2	CO	PM	VOC
U.S. Total, from Central Gen., Industrial Sector	2070.8	3532.3	789322.4	154.2	113.8	17.1
Change due to DG Use	-144.9	-248.2	-15495.6	-10.8	-8.0	-1.2
Net total	1,925.9	3,284.1	773,826.8	143.4	105.8	15.9

** Derived from energy use and assuming an annual load factor of .8

Table 30. Summary of Customer Distributed Generation Air Emissions Impacts

Technology	US Industrial Economic Market Potential (GW)	Air Emissions											
		NO_X		SO_2		CO_2		CO		PM		VOC	
		tons (K)	△ (%)	tons (K)	△ (%)	tons (K)	△ (%)	tons (K)	△ (%)	tons (K)	△ (%)	tons (K)	△ (%)
Central Generation	170.9	2,071	0.0	3,532	0.0	789,322	0.0	154.2	0.0	113.8	0.0	17.1	0.0
Microturbine	20.7	1,964	-5.2	3,260	-7.7	783,290	-0.8	265.2	+71.9	109.6	-3.7	17.7	+3.1
ATS	119.8	1,219	-41.1	1,916	-45.8	688,123	-12.8	150.2	-2.6	82.5	-27.4	17.5	+2.2
ATS -Cogen	86.3	1,119	-46.0	1,781	-49.6	564,573	-28.5	98.2	-36.3	74.2	-34.8	12.3	-28.4
Dual Fuel Engine	20.7	2,374	+14.6	3,262	-7.6	783,831	-0.7	1,636	+960.6	128.5	+13.0	57.5	+235.9
Conv. Fuel Cell	0.0	2,071	0.0	3,532	0.0	789,322	0.0	154.2	0.0	113.8	0.0	17.1	0.0
Advanced Fuel Cell	12.2	1,926	-7.0	3,284	-7.0	773,827	-2.0	143.4	-7.0	105.8	-7.0	15.9	-7.0

Summary of Customer Results

The market potential of distributed generators is calculated by DUVal-C as a percentage of the maximum market potential of 170.9 GW in the year 2002. Table 30 contains summary data for the customer results for 2002 and 2010, respectively.

The results showed that in three states, Indiana, Louisiana, and Ohio, no distributed generation technologies were cost-effective for customer applications. The results for the other seven states (California, Illinois, Michigan, New York, Pennsylvania, Tennessee and Texas) are as follows:

Microturbines

Microturbines are cost-effective in Michigan and New York for about 10.6 GW of customer load (see Table 24). That level of adoption, extrapolated nationally to 20.7 GW, would decrease most air emissions modestly; the exception being a substantial increase in CO.

Advanced Turbine System (ATS)

The ATS is competitive in all seven states, for a total of 61.2 GW, extrapolated to 119.8 GW nationally (see Table 25). Air emissions would be substantially reduced in all categories except VOC, which would increase by a minuscule 0.4%.

Adding CHP capability to the ATS results in slightly lower levels of market potential: 44.0 GW in six states (excluding Texas), 86.3 GW nationally (Table 26). However, due to the avoided boiler emissions, air emissions are substantially reduced across the board.

Dual Fuel Engines

Dual fuel engines are competitive only in New York and Michigan for 10.6 GW of customer load, 20.7 GW nationally (Table 27). Modest reductions of SO_x and CO_2 are offset by increases in other emissions, most notably CO and VOC.

Conventional Fuel Cell

Primarily due to its high capital and maintenance costs, the conventional fuel cell is not competitive in any of the ten states studied (Table 28).

Advanced Fuel Cell

The advanced fuel cell is cost-effective only in Michigan, for 6.3 GW of customer load (12.2 GW on a national basis) (Table 29). The result would be a 2% reduction in CO2 emissions and 7% reductions in the other five emissions.

Observations

As would be expected, because emissions from the various distributed generator technologies differ greatly (as do their costs), the environmental impacts of distributed generation also diverge. Emissions impacts from economic distributed generator operation range from notable increases to substantial reductions.

For example, internal combustion engines, though economically viable, do produce higher amounts of NO_X, CO, PM and VOC than existing central generation.

Microturbines seem best suited to applications where run times are limited. Though inexpensive to purchase and install, they are not especially fuel-efficient and thus have relatively high operating costs, and their CO_2 emissions are among the highest of distributed generators (only the diesel is higher).

Combustion turbines (of which the microturbine is one type, as is the ATS) may also lead to increased CO and NO_X emissions. Progress is being made to reduce these emissions, especially NO_X.

Based on these results, the ATS seems to combine key features needed for a superior distributed generator solution: competitive installed cost; proven, well understood concepts and design approaches; and fuel-efficient and reliable operation with low NO_X emissions. The economically competitive use of ATS leads to modest emission reductions except for CO, which increases somewhat.

CHP can increase the economic viability of distributed generator projects to some degree. More importantly, CHP can have a substantial positive impact on air emissions, relative to generation-only projects.

And, of course, fuel cells show great promise because their air emissions are so much cleaner than central station generation across the board – even if they are fueled by natural gas – and they have a fuel efficiency advantage over all but the most efficient central generators.

Customer Perspective – Conclusions

Distributed generation should be an important facet of customer applications whose objectives include any of the following:

- reducing fuel use
- reducing air emissions from electric energy generation and from energy end-use
- reducing energy cost, especially for industrial applications

Each of the distributed generator technologies under consideration showed appreciable market potential, often for divergent reasons.

7. Observations and Conclusions

Utility Perspective

Utility Peaking Distributed Generation

Economic Market Potential

As shown in Table 9, for a potential market of 21,822 MW/yr in 2002, even the least attractive distributed generation option evaluated (a microturbine) is less expensive than the utility grid option for more than 31% of new load. Dual-fueled engines and small conventional combustion turbines are cost-effective for about 35% and 32% of load growth, respectively. Spark-gas engine gensets and the ATS are more cost-effective than the grid in about 51% and 69% of cases, respectively. Diesel engines are the most cost-effective: they have competitive cost in about 74% of situations.

In 2010 the potential market is 22,163 MW/yr. As shown in Table 10, economic market potential increases considerably for most distributed generators: dual fueled engines are then cost-effective for 49% of new load, conventional combustion turbines increase to 72%, ATSs improve to 78%, and microturbines increase to 66%. Spark-gas and diesel engines hold fairly steady at about 52% and 74%, respectively.

As discussed previously, utility-owned peaking units' cost-effectiveness is driven by their ability to provide electric <u>capacity</u>, when needed, at a cost that is lower than the utility's avoided cost for the grid solution. The results in Tables 9 and 10 indicate that, in many cases, distributed generators are able to meet that requirement.

Economic market potential estimates for peaking distributed generators tend not to be driven by variable operation cost because distributed generators have to operate for so few hours per year to yield cost-effective capacity benefits. This is especially true for diesel engines, the distributed generator option with the lowest installed cost, highest variable cost and most significant emissions.

Therefore, the overall competitiveness of distributed generators for utility peak capacity applications is driven primarily by the fact that, in many cases, distributed generation alternatives have a low initial cost relative to many grid-based solutions involving central generation and "wires" (transmission and distribution) systems.

Virtually all cost-effective distributed generator deployment is at or near customers' loads, as opposed to being located at the utility distribution substation. These feeder locations are preferred because of the potential to avoid additional distribution costs and the potential reliability benefit earned by distributed generators located nearer to loads. It is important to note that many utilities do not allow "islanded" operation of distributed generators during grid outages; this type of operation would be necessary in order for a distributed generator to receive the relatively small reliability credit.

Beyond quantifiable benefits (avoided costs) distributed generators offer an increasingly important way for utilities to reduce risk associated with more permanent grid-based solutions in times of growing uncertainty in the utility marketplace.

Emissions

Engine-based peaking technologies generally produce greater amounts of emissions per unit of energy generated, compared to the existing mix of central generation. The exception is SO_X, which is generally lower thanks to essentially sulfur-free natural gas and diesel fuel and improved ignition controls.

Combustion turbine-based technologies can be substantially cleaner than central generation in many cases. Technological advances in efficiency and NO_X control systems, coupled with natural gas fuel, contribute to lower emissions in today's combustion turbines.

Another important comparison for peaking distributed generators may be between distributed generators and the type of central station generation plant that would have to be used (or whose output would be purchased) if the distributed generator were not used. That additional central station capacity may be an existing plant that was not in use, for a variety of reasons; a refurbished or upgraded plant; or an entirely new plant.

Utility Baseload Distributed Generation

Economic Market Potential

For 2002 (results are shown in Table 11) the Advanced Turbine System (ATS) is the only baseload distributed generator option that is less expensive than the utility grid option, and only for about 3% of the total market of 21,822 MW/yr.

For 2010 (see Table 12), the ATS still has a small market share, but now the advanced fuel cell is cost-effective for over 51% of the available market of 22,163 MW/yr.

Overall, economic market estimates shown in Tables 11 and 12 indicate that most baseload distributed generators will have difficulty competing with central generation. This is primarily due to two factors: 1) a maturing central generation fleet with relatively low financial carrying costs; and 2) low incremental production cost for electric energy from nuclear, hydro, fossil fuel and more modern and efficient combined-cycle combustion turbine-based power plants.

As with utility peaking distributed generators, beyond quantifiable benefits (avoided costs) baseload distributed generators may provide a means for utilities to reduce the risk associated with permanent grid-based solutions as deregulation takes hold in the electric utility marketplace. Electric service reliability enhancements are also possible with distributed generation.

Emissions
Due to minimal market penetration, the implications for air emissions in 2002 are limited. However, in 2010, the advanced fuel cell could have a great effect on air emissions, essentially reducing emissions by half compared to central generation.

Fuel cells are superior to all other distributed generators with regard to emissions. But installed cost for fuel cells is and will continue to be too high for them to claim a significant economic market potential for at least the next four to six years. In the long term, ongoing research and development efforts are expected to reduce fuel cell costs.

Customer Perspective

Distributed generation was not economic at all in three states: Indiana, Louisiana and Ohio. In Michigan, all technologies were cost-effective both on-peak and off-peak, except for the conventional fuel cell, which was not economic at all. In New York, all technologies were economic to some degree, except for both conventional and advanced fuel cells. The standout technology was the ATS: it showed market potential in all seven remaining states; in five of those states it is economic to run the ATS at all times, both on-peak and off-peak. Adding CHP makes the ATS competitive in six states, in all of which it is economic to run the ATS at all times.

Extrapolating the ten-state results to the total US industrial market, the ATS would be competitive for about 120 GW/yr of new load. The microtubine and dual fuel engine could capture about 21 GW/yr, and the advanced fuel cell about 12 GW/yr. As the table below shows, NOX levels could be considerably improved compared with the levels that would be contributed if central utility generation were to serve this load growth instead.

Electric utility industrial customers will tend to use distributed generators primarily to avoid peak demand charges, and also to avoid high electric energy prices during on-peak price periods. Only if a distributed generator is very fuel-efficient, or if CHP is employed, will customer-owned distributed generators tend to operate enough to serve all the customer's electricity needs for the entire year (i.e., few distributed generators can compete with the grid for off-peak electric energy).

Because of deregulation and competition, utilities have unbundled the price for electricity into fixed and variable components, e.g., for generation, transmission, and distribution equipment (fixed costs) and the cost for fuel (variable costs). Electric energy is a variable cost and is priced according to the time that it used, because the cost to produce electricity varies throughout the year. This is referred to as time-of-use (TOU) pricing. Fixed costs associated with utility generation, transmission and distribution equipment for capacity upgrades are reflected as separate components of utility price, i.e., demand charges. These charges may also be time-specific.

At the same time, new distributed generators and vendors offer a growing array of options to utility customers who have become willing to consider alternatives to grid electricity.

Beyond direct cost reduction, another driver of customer use of peaking distributed generators is improvement of service reliability. Some utility customers may install distributed generators to improve the reliability of their electric service beyond levels of reliability that a utility can or will offer. That may be the most compelling reason for specific customers to install peaking distributed generators. If reliability-related benefits are coupled with a credit for peak electric demand reduction (from the utility), then distributed generators may be quite attractive.

The economics of customer distributed generation are strongly driven by utility rate structures and fuel costs. As of this writing, there is more than a little concern that utility rates and natural gas costs may rise in the near future, which would significantly impact the customer model results.

Distributed Generator Emissions

As would be expected, because emissions from the various distributed generator technologies differ greatly (as do their costs), the environmental impacts of distributed generation also diverge.

When comparing distributed generators to the mix of utility central generation, turbine based technologies compare favorably to central generation on an emissions basis. For example, referring to Table 9, in 2002 the microturbine contributes about 1,590 fewer tons of NO_X when used in economical utility peaking applications, compared to central generation. The ATS would contribute about 4,810 tons less, and conventional combustion turbines about 1,650 tons less. Reductions also occur for CO_2 and SO_X. The ATS also reduces CO, while the other two turbine technologies show increases in CO. These results are even more pronounced in 2010 (see Table 10) as market shares increase and emissions factors improve due to technological advancements.

Fuel cells are the cleanest of the distributed generation technologies studied, and would reduce all pollutants by substantial amounts. For example, in 2010 (Table 12), when the advanced fuel cell becomes cost-effective, it could reduce NO_X by more than 50% compared to central generation only (92,700 tons of NO_X vs. 188,700 tons), in utility baseload applications. Other pollutants are similarly reduced, as well.

Reciprocating engine technologies, though economically viable for situations requiring shorter run-times, do produce higher NO_X and CO emissions on a lb/kWh basis than central generation. For example, referring again to Table 9, in 2002 dual fuel engines, spark engines and diesel engines show increases of 4,900, 2,600 and 21,600 tons of NO_X relative to central generation only. CO levels are also considerably higher, and the diesel engine is higher in all categories except for SO_X. Therefore, in regions with central generating plants that emit relatively little NO_x and with high cost electricity (and thus high price), gas fueled engines may indeed be cost-effective but may result in increases in $NO_{X,}$ CO, CO_2 and particulate emissions. Research and development continues in this area and steady progress is expected with regard to engine NO_X and CO emissions.

Microturbines seem best suited to applications where annual run times are low. Though projected to be inexpensive to purchase and install, they are not especially fuel-efficient and thus have relatively high operating costs. CO_2 emissions are higher than those of other distributed generators except Diesel engines.

Small combustion turbines can emit significant amounts of CO and NO_x, especially when compared to existing larger central generating plants. Progress is being made to reduce these emissions, especially NO_X. Unless forbidden by air emission regulations, lower cost peaking units seem destined to emit 25 ppm NO_X or less; microturbine advocates have targets of 10 ppm or less (perhaps much less) for systems used for baseload operation and/or located within air quality non-attainment areas.

Based on this study's results, the ATS seems to combine key features needed for a superior distributed generator solution: competitive installed cost; proven, well understood concepts and design approaches; and fuel-efficient and reliable operation with relatively low NO_X emissions.

Fuel cells show great promise because their air emissions are so much lower than those from combustion-based distributed generators and central station generation. Fuel cells' emissions are inherently lower because of the fuel-to-electricity-conversion process used, and they have a fuel *efficiency* advantage over all but the best central generators. CHP for fuel cells would have a somewhat less dramatic effect on economic competitiveness than for the ATS because, in general, less heat can be recouped from fuel cell operation than from turbines. However, two fuel cell technologies for which CHP may be feasible are solid-oxide and molten-carbonate fuel cells, which have considerably higher operating temperatures than phosphoric-acid and PEM fuel cells.

CHP increases the economic viability of distributed generator projects significantly. CHP also has an important, often significant incremental impact on air emissions (relative to generation-only projects).

Other Observations

Economic market potential estimates are just that: potential. In actuality, adoption of distributed generation, even though cost-effective, will only ramp up slowly, based on a wide range of factors such as unfamiliarity with the technologies, most energy users' lack of sophistication regarding energy costs and technology, the reluctance of regulators to allow "wires" utilities to own and operate distributed generators, local air regulations, etc. A separate evaluation would be required to perform a more refined estimate of the rate of market adoption.

Next Steps and R&D Needs

Since the original intent of this study was to examine the distributed generation emissions "from 30,000 feet," and because the distributed generation technologies and market factors are evolving rapidly, many aspects of this analysis seem worthy of further study or refinement. A few such issues are described below.

Perhaps the most important next step might be to broaden the customer segments to include commercial or even residential sectors, since the price paid for electricity directly determines the customer market penetration. The industrial customer rates used herein were very low compared to those of commercial or residential customers; even the proposed industrial rates used in this study have since been revised.

Distributed generation technology continues to advance and market applications expand. Microturbines have been developed whose size matches commercial customers very well and whose emissions are promising. Recent residential fuel cell technology announcements may accelerate their market entry, either for individual residences, multiple residence buildings or in microgrids. Power quality issues and reliability for critical loads may add value to distributed generation installations and hence accelerate market entry.

Some real-world market factors may now be ready for inclusion or refinement, such as exit fees, standby charges or interconnection costs for customer owned distributed generation. Similarly, the real availability of natural gas to candidate sites, uncertainty regarding future costs of natural gas, costs for gas connection, and firmness of service may warrant further analysis.

Another emerging market niche is the activation of standby generators, especially for temporary service to help utilities get through summer peaks. While these markets were addressed in a cursory manner, the real costs of activation, conversion of Diesel units to natural gas (full or partial conversion), implications of the advent of cleaner reciprocating engines, and the expected hours of operation in such service were not fully analyzed.

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Glossary of Terms, Abbreviations and Symbols

AC – alternating current
APCD – air pollution control district
AQMD – air quality management district
ATS – Advanced Turbine System
BACT – best available control technology
BARCT – best available retrofit control technology
B/C – benefit-cost ratio
bhp – brake horsepower (1 bhp = 746 Watts)
Btu – British thermal unit
CARB – California Air Resources Board
CC – combined cycle
CEC – California Energy Commission
CHP – combined heat and power (cogeneration)
CO – carbon monoxide
CO_2 – carbon dioxide
CT – combustion turbine
D – distribution
DC – direct current
DER – distributed energy resources
DG – distributed generation
DR – distributed resources
DSM – demand-side management
DUVal – Distributed Utility Valuation model (utility)
DUVal-C – Distributed Utility Valuation model (customer)
EPA– Environmental Protection Agency
ESP – electric service provider
FERC – Federal Energy Regulatory Commission
g – gram
G – generation, central-station
GW – gigaWatt(s)
HHV – high heat value (before considering losses)
IC – internal combustion
kW – kilowatt(s)
kWh – kilowatt-hour(s)
lb – pound(s)
LHV – low heat value (net after losses)
MMBtu – million Btu
MW – megawatt(s)
NG – natural gas
NO_x – oxides of nitrogen
O&M – operation and maintenance (costs)
PCU – power conditioning unit
PEM – proton exchange membrane (fuel cell)
PM – particulate matter
ppm – parts per million
PV – photovoltaic(s)
SCF – standard cubic foot
SO_x – oxides of sulfur
T – transmission
T&D – transmission and distribution
TOU – time of use (pricing)
UDC – utility distribution company
UHC – unburned hydrocarbons
VOC – volatile organic compounds
Watt – unit of power

Appendix A. Description of Distributed Generators

Leading distributed generation technologies used in this study were selected because they were considered to be cost-effective, more efficient, cleaner and dispatchable. Renewable technologies such as photovoltaics and wind were not included in the study, due to their non-dispatchability and zero emissions.

Internal Combustion Engine Generators

A reciprocating (piston-driven) internal combustion engine generator set (genset) includes an internal combustion engine as prime mover coupled with an electric generator. The engine is usually one of two types:

1) "spark-ignited" combustion of fuel – gasoline fueled automobile engines employ the Otto heat cycle
2) compression ignition of fuel (diesel heat cycle) – fuel is combusted by compressing it, causing heat leading to ignition of fuel.

Diesel Fueled Diesel Engine Gensets

This type of power plant consists of a diesel-cycle engine prime mover, burning diesel fuel, that is coupled to an electric generator. The diesel engine operates at a high compression ratio and at relatively low rpm (compared to Otto cycle/spark engines and to combustion turbines). Ignition systems are not used, as the diesel fuels combusts under compression.

Diesel engine gensets are very common worldwide, especially in areas where grid power is not available or is unreliable. They are manufactured in a wide range of sizes up to 15 MW; however, for typical distributed energy applications, multiple small units, rather than one large unit, are installed for added reliability.

These power plants can be cycled frequently and operate as peak load power plants or as load-following plants. In some cases, usually at sites not connected to a power grid, diesel gensets are used for baseload operation (sometimes referred to as "village" power). Diesel gensets are proven, relatively simple, and extremely reliable, and should have a service life of 20 to 25 years if properly maintained.

Depending on duty cycle and engine design, O&M for diesel gensets can vary widely, typically from two to five ¢/kWh. Frequent cycling increases O&M costs considerably. Typical diesel genset heat rates (HHV) range widely from 9,500 Btu/kWh up to 13,000 Btu/kWh.

Nitrogen oxide (NO_X) emissions are usually the major concern with respect to siting and permitting of a diesel engine plant though exhaust cleanup and combustion improvements that reduce emissions occur regularly. Particulate emissions must be addressed and SO_2 may be an issue if the sulfur content of the oil is high. Carbon monoxide (CO) emissions may also be an issue. If diesel gensets are too noisy, sound attenuation enclosures may be needed.

Increasingly, diesel engines are being redesigned to run on natural gas, especially where emissions and environmental permitting are issues. However, diesel-cycle engines cannot operate on natural gas alone because natural gas will not combust under pressure like diesel fuel does, so they must operate in what is called "dual fuel" mode. Natural gas is mixed with a small portion of diesel fuel so that the resulting fuel mixture (i.e., 5 – 10% diesel fuel) *does* combust under pressure. This requires modest modifications to, and de-rating of, a diesel-cycle engine.

Natural Gas Fueled Internal Combustion Engine Gensets

A natural gas fueled genset includes a reciprocating (piston-driven) internal combustion engine as prime mover coupled with an electric generator. The engine prime mover is usually one of two types:

1) "spark-ignited" combustion of natural gas (Otto heat cycle), whose operation is very similar to gasoline fueled automobile engines, or
2) "dual-fueled," diesel heat cycle engines modified to use *mostly* natural gas as described in the previous section

Although diesel and spark-ignition engines used for transportation applications are common, natural gas fueled versions are not so ubiquitous. But because the underlying technology is commercial and well known, in theory natural gas fired versions (for power generation) could become much more common in sizes ranging from kilowatts to megawatts. (For distributed energy systems small multiple unit systems would probably be installed rather than one single large unit, to improve electric service reliability.)

Natural gas-fueled reciprocating engine gensets can be cycled frequently to provide peaking power or load-following or they can be used for baseload or cogeneration applications. They employ mostly well-proven technology and are very reliable. Service life should be at least 20 to 25 years if properly maintained.

O&M cost is similar to, and possibly somewhat lower than, that for diesel gensets. It typically ranges from two to five ¢/kWh. Frequent cycling increases O&M costs considerably. Typical heat rates (HHV) also have a wide range, from 9,500 to 13,000 Btu/kWh.

Nitrogen oxide (NO_X) emissions are an important characteristic of many natural gas-fueled reciprocating engine gensets as are carbon monoxide (CO) emissions, although control technology is available and improving. Sound attenuation enclosures may be needed if natural gas fueled reciprocating engine gensets are too noisy.

Combustion Turbines

Combustion turbines (CTs) or gas turbines burn gaseous or liquid fuel to produce electricity in a relatively efficient, reliable, cost-effective, and in some instances clean manner. Generically, CTs are "expansion turbines" which derive their motive power from the expansion of hot gases through a turbine with many blades. The resulting high-speed rotary motion is converted to electricity via a connected generator. CTs use a

Brayton heat cycle: A full CT generation system consists of a fuel-air compressor, a combustor, and the turbine itself, combined on one shaft with the generator and ancillary subsystems.

CTs are typically classified as either: industrial or frame types which were designed from the outset for electric power generation and other stationary applications; or aero-derivative types based on light and efficient jet aircraft engine designs.

CT generation systems are commonplace as electricity generators and are available in sizes from hundreds of kilowatts to very large units rated at hundreds of megawatts. CT systems have a moderate capital cost, but they often are used to burn relatively high cost distillate oil or natural gas. CT generation systems should have a minimum service life of 25 - 30 years if properly maintained and depending on how and how often they are used.

Depending on the manufacturer, size and the model of CT, full-load heat rates (HHV) for commercial equipment can range from 8,000 Btu/kWh to 14,000 Btu/kWh. O&M costs are relatively low, due to their simplicity, reliability, standardization of parts and maintenance protocols, and a robust support industry.

CTs can start and stop quickly and can respond to load changes rapidly making them ideal for peaking and load-following applications. In many industrial cogeneration applications they would also make excellent sources of baseload power, especially at sizes in the 5 to 50 MW range.

From an environmental and permitting standpoint, nitrogen oxide (NO_x) emissions from CTs are the primary issue.

Microturbines

Microturbines are small versions of traditional gas turbines, with very similar operational characteristics. They are based on designs developed primarily for transportation related applications such as turbochargers and power generation in aircraft. In general, electric generators using microturbines as the prime mover are designed to be very reliable with simple designs, some with only one moving part. Typical sizes are 20 to 300 kW.

Microturbines are "near-commercial" with many demonstration and evaluation units in the field. Several companies, some of which are very large, are committed to making these devices a viable, competitive generation option. One key characteristic of microturbines is that their simple design lends itself to mass production, should significant demand materialize. Of course, until demand *does* materialize so that manufacturing can scale up economically, microturbines will remain as a “near” commercial option that cannot compete on an economic basis.

On the downside, fuel efficiency is somewhat or even much lower than that of larger combustion turbines and internal combustion reciprocating engines, and emissions are comparable to somewhat lower. Note, however, that if microturbines are used in situations involving use of steam and/or hot water, microturbines can generate electricity and thermal energy (combined heat and power, CHP) cost-effectively. Definitive data on reliability, durability, and O&M costs are just being developed.

Advanced Turbine System (ATS)

The ATS was developed as a small, efficient, clean, low-cost power generation prime mover by Solar Turbines in conjunction with the U.S. Department of Energy. It employs the latest combustion turbine design philosophy and state-of-the-art materials. It generates 4.2 MW. Fuel requirements are about 8,800 – 9,000 Btu/kWh (LHV). Installed cost is expected to be about $400/kW with O&M expected to be below 5 mills per kWh. With advanced emission controls, NO_X can be well below 10 ppm, though the effect on efficiency is not trivial and the effect on installed cost can be significant.

Fuel Cells

Fuel cells are energy conversion devices which thermochemically convert hydrogen (H_2) or high-quality (hydrogen-rich) fuels like methane into electric current very efficiently and with minimal environmental impact.

Fuel cells are very modular (from a few watts to one MW) and are usually categorized by the type of electrolyte used. The most common electrolyte is phosphoric acid. A few molten-carbonate demonstration fuel cells have been built, and solid oxide technology is under development. Polymer electrolytic membrane fuel cells are also under development for transportation and distributed power applications.

A fuel cell system consists of a fuel processor, the chemical conversion section (the fuel cell "stack"), and a power conditioning unit (PCU) to convert the direct current (DC) electricity from the fuel cell's stack into alternating current (AC) power for the grid or for loads and for supporting hardware such as gas purification systems. Unless hydrogen is used as the fuel, prior to entering the fuel cell stack, the raw fuel (e.g., natural gas) must be dissociated into hydrogen and a supply of oxygen from air must be available. Within the fuel cell stack, the hydrogen and oxygen react to produce a voltage across the electrodes, essentially the inverse of the process which occurs in a water electrolyzer. This DC power is converted to AC power by the PCU.

Fuel cells are not common, although hundreds are in service worldwide and the number of units in service is growing rapidly. Advocates are awaiting expected manufacturing advances that will reduce equipment costs and improve efficiency, so that fuel cells will become more cost-effective. Typical plant unit sizes (which can be aggregated into any plant output rating needed) are expected to range widely from a few kW to 200 kW.

O&M cost for fuel cells is expected to be similar to that for baseload combustion technologies in the near term, ranging from about one to two ¢/kWh; but O&M costs are expected to be much lower in the future as plant designs mature and as important component materials are perfected.

Current fuel cells based on phosphoric-acid electrolytes have heat rates (HHV) of 9,400 Btu and cost in excess of $2000/kW installed. Advanced fuel cell systems utilizing the emerging proton exchange membrane (PEM) technology are expected to have efficiencies in the 60 to 65 percent range over the next 5 years and ultimately to cost less than $1000/kW installed.

Fuel used by fuel cells is not combusted and because fuel conversion to electricity is relatively efficient, fuel cells' emissions of key air pollutants are much lower than for combustion technologies. This is especially true for NO_X, the major pollution-related concern affecting viability of all reciprocating engine and combustion turbine based options. Carbon monoxide, sulfur dioxide and volatile organic compound (VOC) emissions from fuel cells are also negligible or non-existent.

Appendix B. Combined Heat and Power (CHP) and Boiler Emissions – Assumptions and Calculations

Introduction

This appendix discusses the emissions implications of combined heat and power (CHP) applications for distributed generation. The data used herein reflect the latest information as of 2/1/2001.

Boilers

In the CHP scenario, a distributed generator is used to generate electricity, and a waste heat recovery system is used to provide the process heat for the load application, thereby eliminating the boiler. As a result, air emissions from the boiler are avoided. The avoided boiler was assumed to be natural gas fired and 85% fuel efficient.

Avoided boiler air emissions were calculated based on emission factors from the US EPA report AP-42, Section 1.4: Natural Gas Combustion [12]. This document provides emissions in lbs. per million standard cubic feet (scf) of natural gas input to the boiler.

Of greatest interest are NO_X emissions. The EPA reports a wide range of emission factors for NO_X. This variation is driven by criteria including boiler age, "air quality jurisdiction" within which boilers are located (if any), boiler fuel efficiency, type of combustor, and emission control equipment installed.

Newer boilers located in regions with strict air emission regulations have reported emissions of about 35 – 50 pounds per million scf of fuel input. Older boilers, especially larger ones have reported NO_X emissions of about 290 lb per million scf of gas.

It is assumed that boilers likely to be replaced by DG/CHP systems would not be recently purchased equipment, and therefore not the most environmentally benign. Therefore, the avoided NO_X emissions from the boiler are estimated to be approximately 150 lb per million scf of fuel input to the boiler. Of course, any specific project is likely to vary from this figure, plus or minus.

Often these values are better utilized if expressed in units of pounds per MMBtu of fuel input. Per EPA AP-42, there are 1,020 Btu per SCF. To convert the above values to units of lb/MMBtu, divide them by 1,020. Therefore, for boiler NO_X emissions of 150 lb per million scf of fuel into the boiler:

$$NO_X = (150 \text{ lb}/10^6\text{scf} \div 1{,}020) = 0.14706 \text{ lb/MMBtu}_{in}$$

Generation

The waste heat recovery factor is the portion of waste heat from generation that is recovered during generation operation. It accounts for losses associated with gathering and transporting heat. For combustion turbines, exhaust temperatures are typically several hundred degrees Fahrenheit (e.g., 670 ^{o}F for the ATS). According to Solar Turbines Corp., primary developer of the ATS, the waste heat recovery factor is 0.7 for this technology [5].

To calculate heat recovery, first calculate the waste heat from generation by subtracting the heat energy (Btu) in a kWh of electricity (Btu/kWh) from the generator's heat rate (also in Btu/kWh):

> 9,500 Btu/kWh – 3,413 Btu/kWh = 6,087 Btu/kWh of waste heat, for each kWh generated

Next, apply the waste heat recovery factor, 0.7 in this case, to determine the actual heat recovered:

> 6,087 Btu/kWh * 0.7 = 4,261 Btu/kWh

That is the actual heat delivered to the heat load. But the boiler that would have provided that heat is only 85% fuel-efficient. That means that to get that same 4,261 Btu/kWh delivered from the CHP plant, the boiler would burn:

> 4,261 Btu/kWh ÷ 85% = 5,013 "effective" Btu/kWh from the CHP generator.

Avoided boiler emissions associated with each kWh of electricity generated by the CHP operation are calculated based on that heat recovery. As described above, boiler emissions are expressed in units of pounds emitted per MMBtu of fuel input. That emission factor is multiplied by the number of millions of heat Btu per kWh recovered during CHP operation. The result is the pounds of avoided boiler emissions per kWh of electricity from the CHP plant.

First, convert heat recovered per kWh to units of MMBtu/kWh:

> 5,013 Btu/kWh ÷ 1,000,000 Btu/MMBtu = 0.005013 MMBtu/kWh

The boiler emission factor in units of lb/MMBtu of fuel input to the boiler (described above) is multiplied by that amount of avoided boiler fuel use.

For boiler NO_X emissions of 150 lb/10^6scf of fuel input:

> (0.14706 lb/MMBtu)*(0.005013 MMBtu/kWh)
> = .000737 lb

of boiler NO_X emissions avoided per kWh of electricity from a CHP generator.

Calculating Change in Emissions Due to CHP Operation

First, emissions associated with only the generation plant (i.e., without regard to CHP) are calculated. During hours when the distributed generator operates its emission factors apply. During hours when the distributed generator does *not* operate, the central generation emission factors apply. That yields the total amount of emissions associated with electricity from distributed generation plus electricity provided by the grid.

Next, emissions associated with the distributed generator are compared to the avoided emissions, i.e., the emissions that do not occur because the distributed generator is used. To do that, emissions are first calculated as if the grid supplied *all* electricity, using the central generation emission factors. That amount is then added to the boiler emissions that would have occurred if the CHP did not provide heat needed for the facility. It is assumed that the boiler would have operated during the same hours that the DG/CHP operates.

The calculation for the percent change is as follows:

$$100 * \left[\frac{EF_{DG} * P_{DG} + EF_{G} * (1 - P_{DG})}{EF_{G} + EF_{B} * P_{DG}} - 1 \right],$$

where: EF_{DG} = DG-only emissions factor, lb/kWh
EF_{G} = central generation emissions factor, lb/kWh
EF_{B} = boiler emissions factor, lb/kWh
P_{DG} = fraction of electricity supplied by DG/CHP system

A few details are worth noting:

- An underlying assumption for this study is that if a distributed generator with CHP is installed, the boiler whose heat is being supplied by waste heat from the distributed generator must be removed and cannot be replaced, in accordance with existing air emissions regulations. For this to be feasible, the generator must be approximately as reliable a heat source as the boiler was. In addition, if the generator is to serve as a "replacement" for the boiler as a facility's heat source, it may have to be operated when incremental operation cost exceeds the time value of electricity plus avoided boiler fuel cost. In this case, the project's overall financial benefits may be reduced.

- Boiler emissions factors are expressed in units of lb/kWh of generation from the distributed generator. Those emission-specific factors are a function of: a) distributed generator fuel efficiency, b) distributed generator waste heat recovery factor, c) boiler fuel efficiency, and d) pounds of emissions from boiler per MMBtu of fuel input, per US EPA AP-42.